LOAD AND CUSTOMERS

1. INTRODUCTION

This exhibit provides information on Toronto Hydro's revenue load forecast used in developing rates for 2025 to 2029. This exhibit also provides information on the utility's revenues, customer counts, historical annual loads and the incorporation of conservation demand management ("CDM") into the load forecast. This exhibit also describes the methodology used to incorporate the impacts of electric vehicles ("EVs") and distributed energy resources ("DERs") in the revenue load forecast for the period 2025 to 2029.

Toronto Hydro's total load, customer, and revenue forecast is summarized in Table 1. The revenue forecast is calculated based on proposed distribution rates, excluding commodity charges, rate riders, and all other non-distribution rates.

Table 1: Total Load, Revenues, and Customers

		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($Million)	Total Customers
2018	Actual	24,701.0	39,823.2	736.6	770,333
2019	Actual	24,429.6	39,126.0	766.2	777,369
2020	Actual	23,674.7	36,813.7	727.8	781,374
2021	Actual	23,575.0	36,638.0	761.8	786,258
2022	Actual	23,990.1	37,648.0	786.5	790,699
2023	Bridge	23,678.6	37,199.3	834.3	794,025
2024	Bridge	23,676.2	36,993.9	874.3	797,318
2025	Forecast	23,458.7	36,384.5	972.4	800,374
2026	Forecast	23,416.5	36,063.4	1,019.7	803,344
2027	Forecast	23,389.6	35,698.8	1,059.1	806,017

		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($Million)	Total Customers
2028	Forecast	23,498.8	35,507.1	1,151.0	808,731
2029	Forecast	23,458.5	35,093.4	1,185.1	811,245

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

Toronto Hydro's detailed revenue load forecast by rate class, customer forecast by rate class and forecast of distribution revenues by rate class (OEB Appendix 2-IB) are shown in Exhibit 3, Tab 1, Schedule 2.

The information provided for this exhibit has been prepared in accordance with of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022).

2. CUSTOMER FORECAST

The customer base within Toronto Hydro's service territory has displayed continuous growth over the past five years, driven mainly by Residential and Competitive Sector Multi-Unit Residential ("CSMUR") customer additions.

Table 2 shows a summary of the historical and forecasted customer numbers:

Table 2: Customer Numbers by Rate Class

Year		Residential	Competitive Sector Multi-Unit Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000-4,999 kW	Large Use	Street Lighting	Unmetered Load	Total
2018	Actual	612,262	75,028	71,266	10,470	427	42	1	839	**770,333**
2019	Actual	614,206	79,882	71,515	10,444	455	40	1	827	**777,369**
2020	Actual	614,229	83,686	71,899	10,213	480	44	1	824	**781,374**
2021	Actual	614,181	88,478	72,408	9,846	482	45	1	819	**786,258**
2022	Actual	614,926	92,126	72,614	9,731	461	42	1	799	**790,699**
2023	Bridge	615,795	94,391	72,871	9,672	455	47	1	793	**794,025**
2024	Bridge	616,778	96,411	73,152	9,685	453	46	1	793	**797,318**
2025	Forecast	617,563	98,427	73,396	9,699	451	45	1	793	**800,374**
2026	Forecast	618,292	100,404	73,632	9,712	462	48	1	793	**803,344**
2027	Forecast	618,985	102,150	73,857	9,725	460	47	1	793	**806,017**
2028	Forecast	619,849	103,674	74,165	9,740	463	46	1	793	**808,731**
2029	Forecast	620,742	104,994	74,455	9,754	461	46	1	793	**811,245**

In the 2020-2024 rate application decision, the OEB directed Toronto Hydro to enhance its approach to forecasting the number of customers by incorporating economic and demographic conditions.[1] In response to the OEB's direction, Toronto Hydro considered economic, demographic, market knowledge, and reclassification as it developed the forecast for the 2025-2029 period.

The utility enhanced its forecasting methodologies by using stepwise regression techniques where applicable. Numerous explanatory variables were tested with the ultimate model being determined based on model statistics and expert judgment. The methodology was used for the Residential, General Service ("GS") <50 kW, and GS 50-999 kW rate classes. The customer forecast for these rate classes considers customer population, employment, customer trends, and lagged variables.[2] The forecasts of Toronto's employment and population are based on the Conference Board of Canada forecasts.[3] Exhibit 3, Tab 1, Schedule 1, Appendix H contains the historical and forecast customer and input variable details. The model statistics for each class model are shown in Exhibit 3, Tab 1, Schedule 1, Appendix I.

The customer forecast for GS 1000-4999 kW, Large Use, CSMUR, and Street Lighting rate classes are based on market knowledge of construction in Toronto Hydro's service area, as well as an application of expert judgement. Toronto Hydro regularly communicates with developers, municipal representatives and commercial and residential associations to identify new larger connection projects and their expected connection years. Large

[1] EB-2018-0165 Decision and Order, (December 19, 2019) at page 126.
[2] To account for the influence of the previous period's customer numbers, in what is known as an autoregression. This is a way to avoid error terms reflecting a systematic pattern (Gujarati, 2004); and rid the model of autocorrelation (Keele and Kelly, 2006.)
[3] Conference Board of Canada, *Major City Insights – Toronto Census Metropolitan Area* (February 2023).

connection types include data centres, transit electrification, and commercial and residential buildings.

Toronto Hydro's detailed forecast of customers by rate class is found in Exhibit 3, Tab 1, Schedule 2 (OEB Appendix 2-IB).

3. HISTORICAL LOADS

Toronto Hydro's historical total system load (actual and weather-normalized) is illustrated in Figure 1 below.

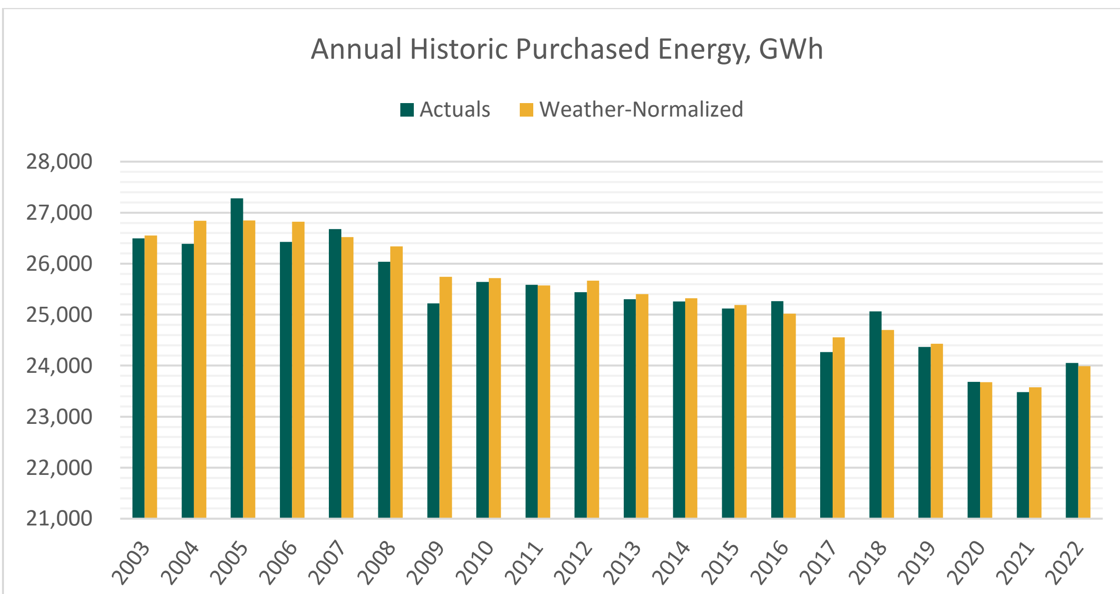

Figure 1: Historical Purchased Energy

Since 2006, Toronto Hydro has experienced a significant decrease in total energy consumption. The flat growth over the 2004-2006 period has been replaced by declining loads over the 2007-2022 period. Conservation activities – both program driven and naturally occurring – are likely continuing to impact the overall load change, as supported by the statistical significance of the CDM explanatory variable in the regression models.

Table 3, below, shows a summary of the total historical normalized annual loads and growth.

Table 3: Historical Annual Load

Year	Total Normalized GWh	Growth GWh	Percentage Change (%)
2003	26,550.6		
2004	26,839.3	289	1.1%
2005	26,845.7	6	0.0%
2006	26,823.2	(22)	-0.1%
2007	26,519.9	(303)	-1.1%
2008	26,341.1	(179)	-0.7%
2009	25,744.0	(597)	-2.3%
2010	25,720.1	(24)	-0.1%
2011	25,573.2	(147)	-0.6%
2012	25,665.6	92	0.4%
2013	25,401.4	(264)	-1.0%
2014	25,323.7	(78)	-0.3%
2015	25,188.6	(135)	-0.5%
2016	25,021.5	(167)	-0.7%
2017	24,557.7	(464)	-1.9%
2018	24,701.0	143	0.6%
2019	24,429.6	(271)	-1.1%
2020	23,674.7	(755)	-3.1%
2021	23,575.0	(100)	-0.4%
2022	23,990.1	415	1.8%

4. BASE REVENUE LOAD FORECAST

Toronto Hydro developed separate load forecasts for each rate class. For rate classes whose billing units are monthly peak demand, the forecasted monthly non-coincident peak by class is forecast based on historical relationships between energy and demand; The summation of the individual rate class loads is referred to as the base revenue load forecast. The impacts of EVs and DERs was accounted for using an integration model described below in Section 10 to arrive at the total load revenue forecast. Revenues are determined by applying the proposed distribution rates to the rate class billing determinants for the forecast period.

4.1 Multivariate Regression Model

Toronto Hydro's process of developing a model of energy usage for each rate class involves estimating multifactor regression models using different input variables to determine the best fit. Different models were fit based on reasoned assumptions about which input variables impact energy use. Using stepwise regression techniques, numerous explanatory variables were tested with the ultimate model being determined based on model statistics and experience.

The models are developed separately for each rate class. This approach allows for greater detail in modelling loads and allows for the different interactions to be modelled independently. All of Toronto Hydro's regression models use monthly kWh per day as the dependent variable and monthly values of independent variables from July 2002 through to the latest actual values (December 2022) to determine the monthly regression coefficients.

The main drivers of energy consumption over time are weather and energy conservation activities (both program and naturally occurring), as well as calendar, economic, and demographic conditions.

5. WEATHER

The primary driver of consumption variance between years is weather. Weather impacts on load are apparent in both the winter heating season and in the summer cooling season. For that reason, both Heating Degree Days ("HDD" – a measure of coldness in winter) and Cooling Degree Days ("CDD" – a measure of summer heat) are captured in the multifactor regression model for all classes except Streetlighting and Unmetered Scattered Load. In previous rate filings, Toronto Hydro had demonstrated that the standard definition of HDD, which uses 18 degrees Celsius as the point at which loads start to be impacted by temperature, was not as effective as a measure which uses 10 degrees Celsius as the "balance point" for the HDD measure. This methodology is consistent with previous Toronto Hydro rate applications (EB-2014-0116 and EB-2018-0165).

Figure 2, below, shows the relationship between temperatures and loads for the period of July 2002 to December 2022. It is clear that the relationship between heating loads and temperature changes at 10 degrees Celsius.

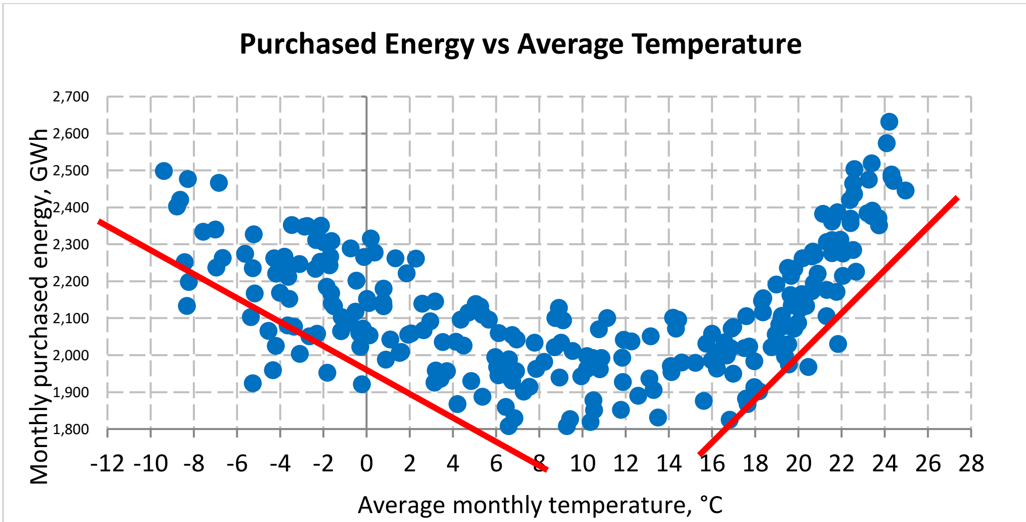

Figure 2: Purchased Energy vs Average Temperature

Positive dew point temperature is another type of weather factor included as an explanatory variable for the CSMUR, GS <50 kW, GS 50-999 kW, and GS 1000-4999 kW customer classes. This variable captures the impact of humidity on consumption and shows the positive impact of temperature on loads during summer months.

The forecast for heating and cooling degree-days, and positive dew point temperature inputs is based on a ten-year historical average of HDD, CDD, and positive dew point. Toronto Pearson International Airport station was used as the climatological measurement point for establishing monthly HDD and CDD.

5.1 Weather Normalization Methodology

Toronto Hydro's forecasts are future (out-of-sample) estimates of monthly load, obtained by extrapolating patterns and relationships from historical (in-sample) observations. These data points are monthly energy (load) purchases that get weather-normalized through adjustments for any deviations relative to the amount of energy that would have been purchased under normal weather conditions. Specifically, any energy amounts either in excess or below what would be purchased under normal weather conditions, are subtracted or added to the purchases of a given month. Calculations are made by using regression coefficients as quantitative measures of the effect of weather conditions on load purchases. In other words, a regression is estimated to model load variations as a function of explanatory variables including weather conditions such as HDD, CDD, and positive dew point temperature. The "beta" or slope coefficients thus obtained are used to measure load increases or decreases resulting from a unit increase in each of those weather determinants. To illustrate the process, if, for example a given summer month was much hotter compared to normal historical actual patterns then the process would involve: a) that month's number of CDD is subtracted from the number of CDD one would observe in an average year; and b) the difference is multiplied by the partial effect, or beta coefficient of CDD, in order to calculate the effect attributable to that weather-related determinant. This is done for all the weather determinants, thus allowing Toronto Hydro to re-calculate load net of abnormal weather effects. This is referred to as a weather normalized load.

6. CONSERVATION AND DEMAND MANAGEMENT (CDM)

Consistent with its previously approved load forecasts in EB-2014-0116 and EB-2018-0165, Toronto Hydro has included CDM activities and their impacts into its forecast for the 2025 to 2029 period. Changes to the availability of CDM savings forecasts and results has necessitated a change in Toronto Hydro's methodology for accounting for CDM.

As noted in the OEB's Chapter 3 filing requirements, on March 20, 2019, the Minister of Energy, Northern Development and Mines issued separate directives to the OEB and the Independent Electricity System Operator ("IESO") in respect of CDM programs. The directive to the IESO concluded the Conservation First Framework ("CFF") effective immediately. New CDM program activity has since been provincially-centralized under the IESO's Interim Framework and 2021-2024 CDM Framework. As a result, the IESO is no longer providing CDM savings forecasts or program results for distributors' service territories.

The latest CDM guidelines for Electricity Distributors (EB-2021-0106) state that distributors may choose to include CDM as a variable in a multivariate regression, based on the historical and forecast level of savings from applicable CDM activities in a given year. Toronto Hydro has moved towards including CDM as a multivariate regression variable to represent conservation that occurs through both CDM program delivery and naturally. The utility previously used a three-step process that explicitly considered cumulative historical and forecast CDM impacts that were added to metered loads (gross of CDM), forecasted based on regression modelling, and then subsequently deducted to derive the load forecast (net of CDM).

Incorporating CDM as a multivariate regression variable allows Toronto Hydro to account for conservation activities through regression techniques with the limited LDC-level information available. Due to the change in methodology, the metered loads are no longer manually adjusted for CDM impacts. The CDM regression variable reflects the declining customer usage from conservation activities, as well as avoids any double-counting of savings. Section 6.1 provides a detailed explanation of the CDM savings used to develop the CDM variables.

Toronto Hydro is currently not planning to establish a Lost Revenue Adjustment Variance Account (LRAMVA) threshold for the 2025-2029 period.[4]

6.1 CDM Multivariate Variables

Toronto Hydro incorporated CDM variables into the multivariate regression: a residential CDM variable for the Residential class, and a business CDM variable for the General Service classes. Both variables are based on the cumulative historical and forecast level of savings from 2006 to 2029, and separated by residential and business program savings for each variable respectively. The variables were found to be statistically significant in the Residential, GS <50 kW, GS 50-999 kW, GS 1000-4999 kW, and Large Use class models. The calculations for each CDM variable are shown in Exhibit 3, Tab 1, Schedule 1, Appendix C.

Toronto Hydro's historical and forecasted annual CDM savings for the 2006 to 2029 period are determined in four separate components:

1) Verified historical savings (2006 to 2017);
2) Post-CFF historical savings (2015 to 2022);
3) 2021-2024 CDM Framework forecast savings (2021 to 2024); and
4) Forecast savings beyond the 2021-2024 CDM Framework (2025 to 2029).

<u>Verified Historical Savings (2006 to 2017)</u>

Toronto Hydro's CDM savings include impacts of historical CDM achievement. The annual impacts of CDM completed between 2006 and 2017 have been verified by the IESO, and represent the full suite of energy efficiency and demand response programs offered to Toronto Hydro's residential and business customer segments.

[4] EB-2021-0106, Ontario Energy Board, *Conservation and Demand Management Guidelines for Electricity Distributors* (December 20, 2021) at page 23-24.

<u>Post-CFF Historical Savings (2015 to 2022)</u>

The second component includes unverified 2015 - 2022 achievements, as well as an extrapolation of CDM savings from the IESO's provincial CDM program delivery. In the absence of final verified annual CDM program results and CDM Plan, Toronto Hydro used the following additional information to determine these savings:

- the IESO's Participation and Cost Reports for January 1, 2018 through April 2019; these reports include incremental first-year energy savings;
- third-party Measurement and Verification Reports for specific projects under the Process and System Upgrades Program, which is not captured in the IESO's Participation and Cost Reports;
- for savings to December 31, 2022 that are related to CFF programs, project-level savings for projects that were completed within the 2015-2022 period which a distributor is contractually obligated to finish. For the Retrofit Projects, energy savings and demand reductions are based on the list of projects for which Toronto Hydro paid incentives to customers and which had their status updated to "Project Closed" in CDM-IS system post March 1, 2019. For non-Retrofit CFF Projects, savings are based on the list of projects for which Toronto Hydro has paid incentives and submitted project-level details to the IESO; and
- IESO's 2019-2020 Interim Framework for the province, extrapolated for savings in Toronto Hydro's service area. The extrapolation is based on Toronto Hydro's 2015-2017 historic ratio of LDC program savings to provincial savings under CFF.

Exhibit 3, Tab 1, Schedule 1, Appendix D contains the summary of 2015 to 2022 Post-CFF historical savings. Exhibit 3, Tab 1, Schedule 1, Appendix F contains the IESO's 2019-2020

Interim Framework CDM plan for the province; the extrapolation for savings in Toronto Hydro's service area are shown in Exhibit 3, Tab 1, Schedule 1, Appendix E.

2021-2024 CDM Framework Forecasted Savings (2021 to 2024)

The third component is based on the IESO's 2021-2024 Conservation and Demand Management Framework for the province, extrapolated for savings in Toronto Hydro's service area. The extrapolation is based on Toronto Hydro's 2015-2017 historic ratio of distributor program savings to provincial savings under CFF. For newer programs that did not exist under CFF, the historic ratio is based on the total sector savings (residential or business).

Exhibit 3, Tab 1, Schedule 1, Appendix G contains the IESO's 2021-2024 CDM plan for the province; the extrapolation for savings in Toronto Hydro's service area are shown in Exhibit 3, Tab 1, Schedule 1, Appendix E.

Forecast savings beyond the 2021-2024 CDM Framework (2025 to 2029)

Toronto Hydro's annual forecasted savings for 2025 to 2029 were developed based on the assumption that there will be a continuation of CDM program delivery by the IESO. In the absence of a new framework, the projected impact is based on the anticipated "status quo" CDM delivery objectives and expectations assigned for the post-2024 conservation planning period. Toronto Hydro has determined this to be the best estimate at this time given the absence of conservation planning detail for this period. This method is consistent with Toronto Hydro's previous application methodology.

7. OTHER MULTIVARIATE VARIABLES

The multivariate regression model captures a number of other multivariate variables in addition to CDM impacts, including demographic and economic conditions, COVID-19 pandemic impacts, time trends and calendar factors.

Demographic and economic conditions are captured within the model by using customer numbers, the Toronto unemployment rate, the Toronto employment numbers, Toronto gross domestic product ("GDP") and time trend variables discussed below. The Toronto unemployment rate, employment numbers and GDP reflect the level of economic fluctuations, and were found to be statistically significant in the Residential, CSMUR, GS <50 kW, GS 50-999 kW, GS 1000-4999 kW, and Large Use class models. Customer variables capture overall levels of demographic fluctuations, and were found to be statistically significant in the CSMUR, GS <50 kW, GS 50-999 kW, and Large Use class models. The forecasts of Toronto's unemployment rate, employment numbers and GDP are based on the Conference Board of Canada forecasts.[5]

Load impacts from the COVID-19 pandemic are captured through a lockdown binary variable. This variable is based on the provincial lockdown periods announced during the pandemic in 2020-2021. Additional load impacts from the pandemic are captured through the economic variables used in the model, such as GDP. The lockdown binary variable was found to be statistically significant in the Residential, GS <50 kW, GS 50-999 kW, and Large Use class models.

The time trend variables used in the model are designed to capture trends which are not otherwise explained by the other driver variables, as well as to improve the overall model

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[5]*Supra* note 3.

fit over the period. The Residential, GS<50 kW, and Large Use classes use a linear spline time trend in the 2012 to 2022 period, the General Service 1,000-4,999 kW class uses a linear spline time trend in the 2018 to 2022 period, and the GS 50-999 kW uses a simple time trend over historical period 2018 to 2022.

One additional factor determining energy use in the monthly model are "calendar factors." For example, the number of business days in a month will impact total monthly load. To capture the different number of days in the calendar months, the modelling of purchased energy was performed on a per-day basis. To reflect different numbers of business days in the month and, consequently, different number of peak hours, business day percentage was used in those class models. A binary variable was also included to reflect the impact of the 2003 August blackout on energy use in that month.

Exhibit 3, Tab 1, Schedule 1, Appendix A contains the historical and forecast load and input variable details. The model statistics for each class model are shown in Exhibit 3, Tab 1, Schedule 1, Appendix B.

From the regression models, the forecast of energy usage is determined by applying the model coefficients to forecasts of the input variables.

Table 4 summarizes the variables included in each of the rate class energy models.

Table 4: Regression Variables by Rate Class

Residential	Competitive Sector Multi-Unit Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000-4,999 kW	Large Use	Street Lighting	Unmetered Load
HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	Average use per device	Simple extrapolation
CDD per day	CDD per day	CDD per day	CDD per day	CDD per day	CDD per day		
Blackout binary variable	Number of CSMUR customers	Number of GS<50 kW customers	Number of GS 50-999 kW customers	Business days percent	Number of Large Use customers		
Time trend	Positive dew point temp	Lockdown binary variable	Lockdown binary variable	Business CDM Variable	Lockdown binary variable		
Unemployment rate	Unemployment rate	Business CDM Variable	Business CDM Variable	Time trend	Business CDM Variable		
Residential CDM variable		Time trend	Time trend	GDP	Time trend		
		GDP	Employment	Positive dew point temp	GDP		
			Positive dew point temp		Positive dew point temp		
			Business days percent		Business days percent		
			Blackout binary variable				

8. ALIGNMENT WITH PEAK DEMAND FORECAST

Toronto Hydro prepares forecasts in addition to the revenue load forecast for other important purposes, including a peak demand forecast.[6] Where the revenue load forecast provides a view of customer consumption and demand over the coming rate period, the peak demand forecast shows the anticipated peak demand at all transformer station buses that supply Toronto Hydro's distribution grid. The peak demand forecast and the revenue load forecast have important differences. The peak demand forecast focuses on the sufficiency of the distribution system's capacity to serve the potential draw on the grid by aggregations of customers at singular points in time, while the revenue load forecast focuses on projecting customer consumption within billing cycles.

The peak demand forecast is a 10-year weather-adjusted peak demand forecast prepared to assist with the planning of capital work programs mainly at the distribution station level (e.g., feeder level) to meet capacity need. The peak demand forecast considers localized growth and density intensification from new high-rise developments, EVs, and other large connections that are driving the need for investments. The forecast is dependent on historical peak load at the bus level as well as bus weather sensitivity. The peak demand forecast is also used to help inform the IESO's regional forecasting process and, internally, in long-term planning. Please see Exhibit 2B, Section B – Coordinated Planning, Appendix A for the Toronto Region System Needs Assessment Report.

In contrast to the peak demand forecast, the revenue load forecast provides an outlook of customer consumption and demand. The revenue load forecast is dependent on monthly historic billing consumption by rate class (as a dependent variable) as well as independent variables from external sources. As described above in section 6,

[6] Exhibit 2B, Section D4.

conservation activities continue to contribute to the overall decline in customer load and demand.

Toronto Hydro ensures alignment between the two forecasts through the use of common growth base inputs, including large connections and electrical vehicles. The large connection projections are based on market knowledge of construction in Toronto Hydro's service area, including confirmed connection agreements. Toronto Hydro developed a forecast of EV uptake as an input to these forecasts. The EV forecasts are inputs in both the load forecast and peak demand forecast for determining their respective outputs. More information on the electrical vehicles is available in Section 10.

9. CLASS DEMAND (kVA) FORECAST

Toronto Hydro's forecast of monthly peak demand by customer class, which is used to determine revenue for those customers billed on a demand basis (GS 50-999 kW, GS 1000-4999 kW, Large User, and Street Lighting), is established using historical relationships between energy and demand. The utility uses the latest five-year average growth of this relationship for forecasting purposes. The resulting kW demand forecast is explicitly converted based on average power factors to determine the peak kVA demand forecast.

10. ELECTRIC VEHICLES AND DISTRIBUTED ENERGY RESOURCES

Toronto Hydro incorporated EVs and DERs into its load forecast. Toronto Hydro expects to see increased use of these technologies as the energy transition unfolds over the 2025-2029 forecast period. It is necessary, therefore, to develop distinct forecasts for these technologies because they are expected to exceed historical market adoption levels.

Given this anticipated acceleration, the base revenue load forecast does not account for the anticipated future load impacts of these technologies.

Toronto Hydro engaged Clearspring Energy Advisors, LLC ("Clearspring") to help develop an approach to including the expected impacts of EVs and DERs into the 2025 to 2029 period. Clearspring developed an integration model for this purpose. The objective of the integration model is to forecast the impacts on energy and billing demand by rate class resulting from the forecasted changes in the adoption of EVs and DERs. These impacts are then aggregated to the base revenue load forecast developed through multivariate regression modelling. Clearspring also produced an analysis on the changes to the rate class load profiles resulting from the EV and DER forecasts that is used as an input in the cost allocation model by Toronto Hydro for rate setting purposes.

The Clearspring integration model used the following forecast inputs, provided by Toronto Hydro, to forecast the impacts of EVs and DERs onto the billing components of energy and demand:

1) Light-duty electric vehicles ("LDEVs"),
2) Medium-duty electric vehicles ("MDEVs"),
3) Heavy-duty electric vehicles ("HDEVs"),
4) Customer-owned renewable DERs ("Renewables"),
5) Customer-owned non-renewable DERs ("Non-Renewables"), and
6) Customer-owned energy storage resources

The integration model estimates the incremental load of these technologies from their 2022 adoption levels to the 2029 forecasted levels.

The six technology inputs were aggregated to the base revenue load forecast to determine the net forecast after accounting for these technologies. The load impacts vary between the technologies as EVs will increase energy and billing demand, whereas DERs will lower energy and billing demand. The forecasted load impacts as a percentage of the total revenue load forecast are provided annually in Table 5 below.

Table 5: Annual Forecasted Energy and Billed Demand Impacts

Year	Incremental Energy (kWh) % Increase	Incremental Billed Demand (kVA) % Increase
2023	-0.1%	-0.1%
2024	-0.2%	-0.2%
2025	0.1%	0.0%
2026	0.7%	0.5%
2027	1.5%	1.1%
2028	2.5%	1.7%
2029	3.4%	2.4%

10.1 Electric Vehicles

Toronto Hydro developed the EV forecast as an input to Clearspring's integration model. The forecast was developed in reference to the three vehicle types: LDEV (battery and plug-in electric), MDEV, and HDEV.

The EV forecast was developed to be consistent with the City of Toronto's EV Strategy targets:[7]

- 2025 – 15% of new vehicle sales and 5% of total light duty vehicles be classified as EVs; and
- 2030 – 40% of new vehicles sales and 20% of total light duty vehicles be classified as EVs, totalling 220,000 LDEVs.

[7] City of Toronto, Electric Vehicle Strategy: https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf.

The LDEV forecast was developed by using historical Light-Duty Vehicles ("LDV") population in Ontario, as well average annual growth rates, for which an extrapolation for Toronto and LDEV forecasts were created. The number of new LDV and LDEV registrations in Ontario were obtained from StatsCan. The reported values were used to estimate the number of new LDVs and LDEVs registered each year in Toronto. It is estimated that approximately 12.7 percent of new vehicles registered in Ontario each year are registered in Toronto. To maintain consistency with the City's EV Strategy the same 11-year average vehicle age was used, which results in approximately 9.1 percent of the vehicle population retiring each year. These factors were used to develop an accounting of the number of LDVs registered in Toronto at the end of each year.

An estimation of the LDV growth in Toronto was created based on the levels seen in 2017-2019 (pre-COVID) from Stats Canada. Toronto's share of Ontario's new vehicles is assumed to be constant over time at 12.7 percent. The forecast of new LDEV registration and total LDEV registered each year was built up to achieve the 220,000 in 2030 EV target provided by the City of Toronto, which would represent 20 percent of the total LDV fleet. The methodology estimates 1.1M LDVs registered in Toronto by 2030, with an annual growth of 1 percent during the forecast period.

The MDEV and HDEV forecasts were also developed using the historical vehicle population in Ontario, as well average annual growth rates, for which an extrapolation for Toronto and EV forecasts were created. With the annual growth rate of both vehicle classes, a provincial wide population forecast was derived. Toronto accounts for approximately 20% of the provincial medium and heavy-duty vehicle population. The HDEV forecast also includes vehicle growth from the Toronto Transit Commission ("TTC"). The TTC's Green Bus Replacement program is key to the City's TransformTO action plan and outlines the transition of the TTC bus fleet to zero-emission vehicles by 2040.[8] An adoption rate was then developed to establish how rapidly MDEVs and HDEVs would need to be adopted to meet the City's EV Strategy Target. A materialization factor was also added to the MDEV and HDEV forecasts as an adjustment to account for delayed adoption. Internal analysis shows that commercial customers typically have delayed completion dates compared to their original estimated completion dates. Internal analysis was based on energization project materialization between estimated and actual completion dates.

Table 6, 7 and 8 below show the summaries of EV forecasts, consumption and billed demand by vehicle type. Please refer to Clearspring's report in Exhibit 3, Tab 1, Schedule 1, Appendix J for further details.

Table 6: EV Forecasts by Vehicle Type

Year	LDEVs	MDEVs	HDEVs
2023	26,408	1,673	1,651
2024	38,615	2,811	2,769
2025	52,764	3,686	3,622
2026	75,653	4,862	4765
2027	105,249	6,057	5,922
2028	142,460	6,982	6,809
2029	179,770	8,215	7,992

[8] Green Bus Replacement Program, Toronto: Toronto Transit Commission, 2022.

Table 7: EV Consumption (MWh) by Vehicle Type

Year	LDEVs	MDEVs	HDEVs	Total EV Load	% of Total Load Forecast
2023	23,643	9,892	30,174	**63,709**	**0.3%**
2024	60,312	26,688	81,282	**168,281**	**0.7%**
2025	106,482	47,219	143,575	**297,276**	**1.3%**
2026	172,215	72,064	218,716	**462,996**	**2.0%**
2027	264,559	101,434	307,251	**673,244**	**3.0%**
2028	381,971	131,035	396,087	**909,093**	**4.0%**
2029	511,753	160,524	484,126	**1,156,402**	**5.1%**

Table 8: EV Billed Demand (kVA) by Vehicle Type

Year	LDEVs	MDEVs	HDEVs	Total EV Billed Demand	% of Total Billed Demand Forecast
2023	3,449	17,741	60,372	**81,561**	**0.2%**
2024	8,799	47,848	162,964	**219,611**	**0.6%**
2025	15,537	84,644	288,185	**388,366**	**1.1%**
2026	25,127	129,176	439,102	**593,405**	**1.6%**
2027	38,602	181,812	617,072	**837,486**	**2.3%**
2028	55,736	234,851	795,856	**1,086,443**	**3.1%**
2029	74,680	287,698	972,887	**1,335,264**	**3.8%**

10.2 Distributed Energy Resources

DER forecasts, developed by Toronto Hydro (see Exhibit 2B, Section E5.1), were provided to Clearspring as an input to the integration model.

The DER forecasts were developed in reference to three technology types:

- **Renewables** – consists of DER based on renewable technologies, such as solar photovoltaic.

- **Energy Storage** – refers to DER related to the capture of energy, such as batteries.
- **Non-Renewables** – refers to conventional fossil-fuel based DER, such as natural gas generators and combined heat and power.

Tables 9, 10 and 11 below show the summaries of DER forecasts, consumption and billed demand by technology type. Please refer to Clearspring's report in Exhibit 3, Tab 1, Schedule 1, Appendix J for further details.

Table 9: DER Forecasts by Technology Type and Installed Capacity (kW)

Year	Renewables	Energy Storage	Non-Renewables
2023	126,443	56,579	198,186
2024	133,449	60,042	212,056
2025	143,426	73,359	215,566
2026	155,110	77,378	218,717
2027	168,502	81,407	221,597
2028	183,601	85,436	224,297
2029	200,407	89,485	226,817

Table 10: DER Consumption (MWh) by Technology Type

Year	Renewables	Energy Storage	Non-Renewables	Total DER Load	% of Total Load Forecast
2023	-4,166	0	-90,664	**-94,830**	**-0.4%**
2024	-9,374	0	-209,470	**-218,844**	**-1.0%**
2025	-14,764	0	-257,450	**-272,214**	**-1.2%**
2026	-21,551	0	-276,758	**-298,309**	**-1.3%**
2027	-29,396	0	-294,254	**-323,650**	**-1.4%**
2028	-38,299	0	-310,463	**-348,762**	**-1.5%**
2029	-48,260	0	-325,623	**-373,883**	**-1.6%**

Table 11: DER Billed Demand (kVA) by Technology Type

Year	Renewables	Energy Storage	Non-Renewables	Total DER Billed Demand	% of Total Billed Demand Forecast
2023	-5,109	0	-124,299	**-129,408**	**-0.3%**
2024	-11,452	0	-288,041	**-299,493**	**-0.8%**
2025	-18,039	0	-354,245	**-372,284**	**-1.0%**
2026	-26,325	0	-380,823	**-407,147**	**-1.1%**
2027	-35,901	0	-404,905	**-440,806**	**-1.2%**
2028	-46,769	0	-427,214	**-473,983**	**-1.3%**
2029	-58,928	0	-448,079	**-507,007**	**-1.4%**

10.3 Integration Model

The integration model's purpose is to convert the EV and DER forecasts into consumption and billing demand outputs for the total load forecast. The model undertakes a four-step process to convert these technologies into consumption and billing demand outputs as follows:

- The model calculates the change in technology forecasts from 2022;
- The technology changes are then allocated by 6 rate classes (Residential, CSMUR, GS <50kW, GS 50-999 kW, GS 1000-4999 kW, Large User);
- The monthly energy impacts of each technology are estimated by rate class in 2025 through 2029; and
- The monthly billing demand impacts of each technology are estimated for the applicable rate classes in 2025 through 2029 (GS 50-999 kW, GS 1000-4999 kW, Large User).

The resulting outputs are aggregated to the base revenue load forecast. Exhibit 3, Tab 1, Schedule 1, Appendix J contains Clearspring's report on the integration of EVs and DERs for revenue forecasting that was designed and developed for Toronto Hydro.

11. HEAT PUMPS

Heat pumps (i.e. the electrification building heating) are another technology associated with the energy transition. In preparing the revenue load forecast for the 2025-2029 period, Toronto Hydro determined that the impact of heat pumps on overall load and demand is not yet material. As such, the potential load impacts of heat pumps were not separately incorporation into the load forecast. Existing heat pump loads are captured, however, in the multivariate regression models.

12. ACCURACY OF FORECAST AND VARIANCE ANALYSES

Table 12 summarizes the variances between Toronto Hydro's actual loads and the last OEB-approved loads (filed in Toronto Hydro's EB-2018-0165 rate filing).

Table 12: Forecast versus Actual Purchased Energy

Year	Board-Approved Load Forecast	Actual Load		Weather Normalized Actual	
	GWh	GWh	Variance	GWh	Variance
2020	24,044.00	23,681.30	-1.51%	23,674.74	-1.54%
2021	23,763.36	23,480.00	-1.19%	23,574.99	-0.79%
2022	23,650.99	24,054.52	1.71%	23,990.12	1.43%

Year to year variances in Toronto Hydro's historical loads reflect the impacts of COVID-19 pandemic, weather, economic conditions, CDM, and normal customer growth. For the forecast periods, year to year variances in loads reflect the impact of model driver variables.

Table 13 summarizes the variances between Toronto Hydro's actual number of customers and the last OEB-approved number of customers (filed in Toronto Hydro's EB-2018-0165 rate filing).

Table 13: Forecast versus Actual Number of Customers

Year	Board-Approved Customer Forecast	Actual Number of Customers	Variance
2020	784,279	781,374	-0.37%
2021	791,003	786,258	-0.60%
2022	799,341	790,699	-1.08%

Tables showing Toronto Hydro's year-over-year actual loads and customers can be found in Exhibit 3, Tab 1, Schedule 2 (OEB Appendix 2-IB).

Toronto Hydro-Electric System Limited
EB-2023-0195
Exhibit 3
Tab 1
Schedule 1
Appendix F

ORIGINAL
(24 pages)

Making a Difference

Energy Efficiency in Ontario

2019-2020 Interim Framework Results

ieso
Connecting Today.
Powering Tomorrow.

SAVE ON ENERGY
POWER WHAT'S NEXT

Save on Energy celebrates 10 years in 2021. More than 250,000 Ontario residents and businesses have relied on Save on Energy programs to better manage their energy use.

10 YEARS OF SAVE ON ENERGY™




Everyone benefits from energy efficiency

It helps:

- enable consumers to better manage their electricity bills
- support businesses in their efforts to stay competitive
- drive economic prosperity
- defer building new power plants and transmission lines
- lower electricity system costs

2019-2020 Save on Energy highlights

$353 M
Invested in Energy Efficiency Projects

1.5 TWh
Total Electricity Savings

186.4 MW
Total Demand Savings

The electricity saved is equivalent to powering a city the size of Oshawa for one year

2019-2020 Save on Energy Programs

- Retrofit
- Small Business Lighting
- Energy Manager
- Process and Systems Upgrade Program
- Energy Performance Program
- Home Assistance Program
- First Nation Programs
- Local Program Fund

Retrofit program

2019-2020 RESULTS:

11,128
Businesses Supported

1.2 TWh
Total Electricity Savings

144.7 MW
Total Demand Savings

Helping business unlock energy savings and improve productivity, employee comfort and customer experience

Case Study:
Dream Office

Dream retrofitted the lighting at 11 office buildings in downtown Toronto, replacing inefficient incandescent and fluorescent bulbs and magnetic ballasts with new energy-efficient and long-lasting LED lighting.

Dream is one of Canada's leading real estate companies, focused on impact investing and sustainable buildings

2M+

Square feet of existing office space retrofitted in a major lighting program

Through direct IESO funding, Dream also hired a full-time Energy Manager to identify energy-saving capital projects and make operational improvements

Through the incentives received from Save on Energy, Dream was able to justify a larger investment and retrofit scope, including a smart lighting control system that can be controlled using a mobile device and provides human-centric lighting

4,947 MWh

Total Electricity Savings

945 kW

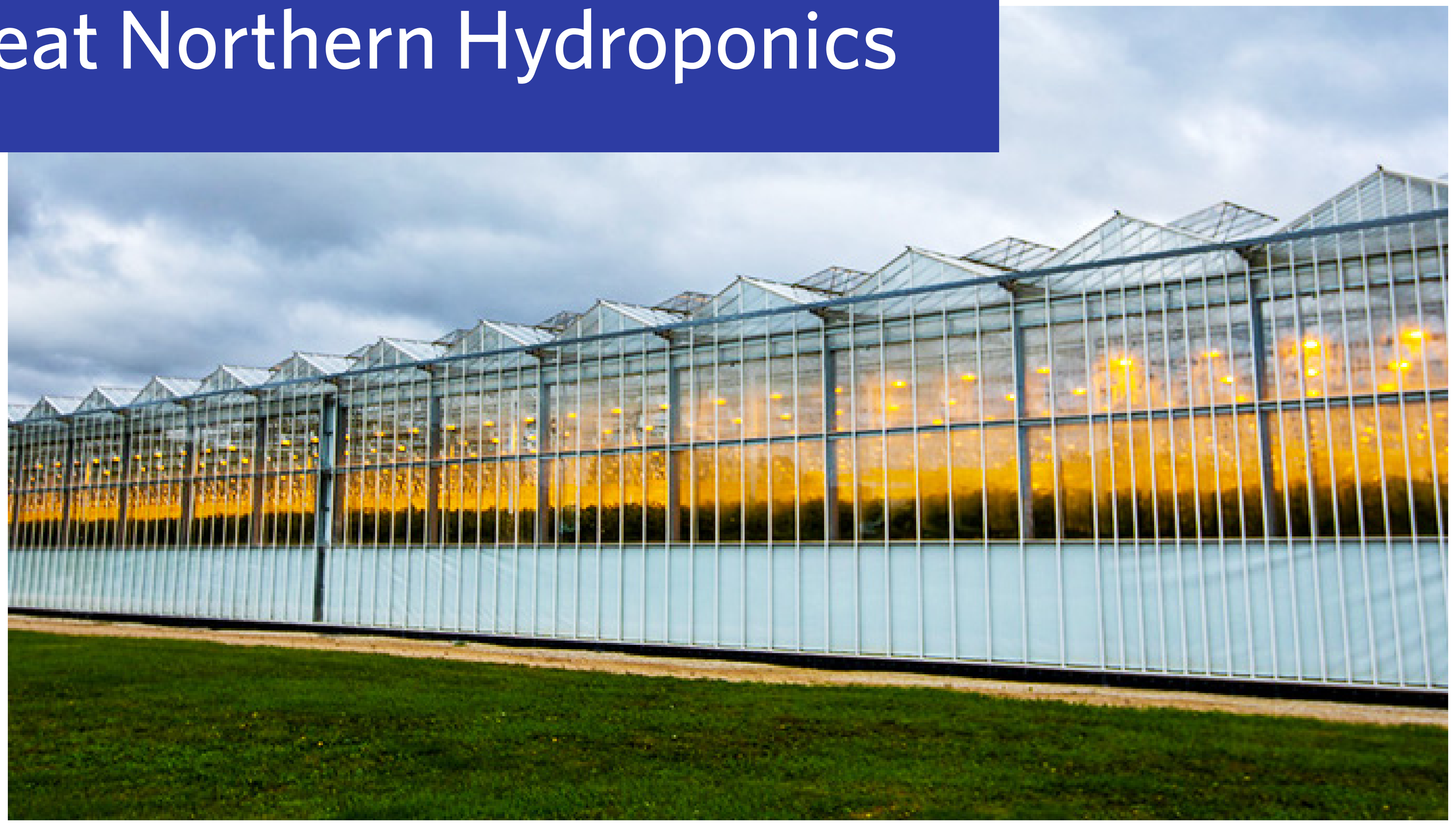
Total Demand Savings

"The IESO has been an important partner for us to achieve our sustainability goals. Leveraging the Save on Energy program enabled a pathway to smarter, more efficient and higher performing buildings."

LEE HODGKINSON
VP, Technical Services, Sustainability & ESG
Dream Office

Case Study:

Great Northern Hydroponics



"We were the first tomato grower to light a crop commercially in this area. If it's a clear sky, the lighting requirement goes down to 50 per cent."

GUIDO VAN HET HOF
President and General Manager
Great Northern Hydroponics

This project is part of an energy-efficiency strategy that also includes measures such as energy curtains and an automation system to control light and heat, which adjusts according to available sunlight.

70-acre
Facility located in Kingsville, Ontario

10
Varieties of tomatoes

$150,000
Expected annual savings in energy costs by replacing half their high pressure sodium (HPS) lights with high-performance LED fixtures

Small Business Lighting program

2019-2020 RESULTS:

6,826
Businesses Supported

47.2 GWh
Total Electricity Savings

11.6 MW
Total Demand Savings

Providing small businesses with up to $2,000 to increase visibility and safety and help reduce energy costs

Energy Manager program

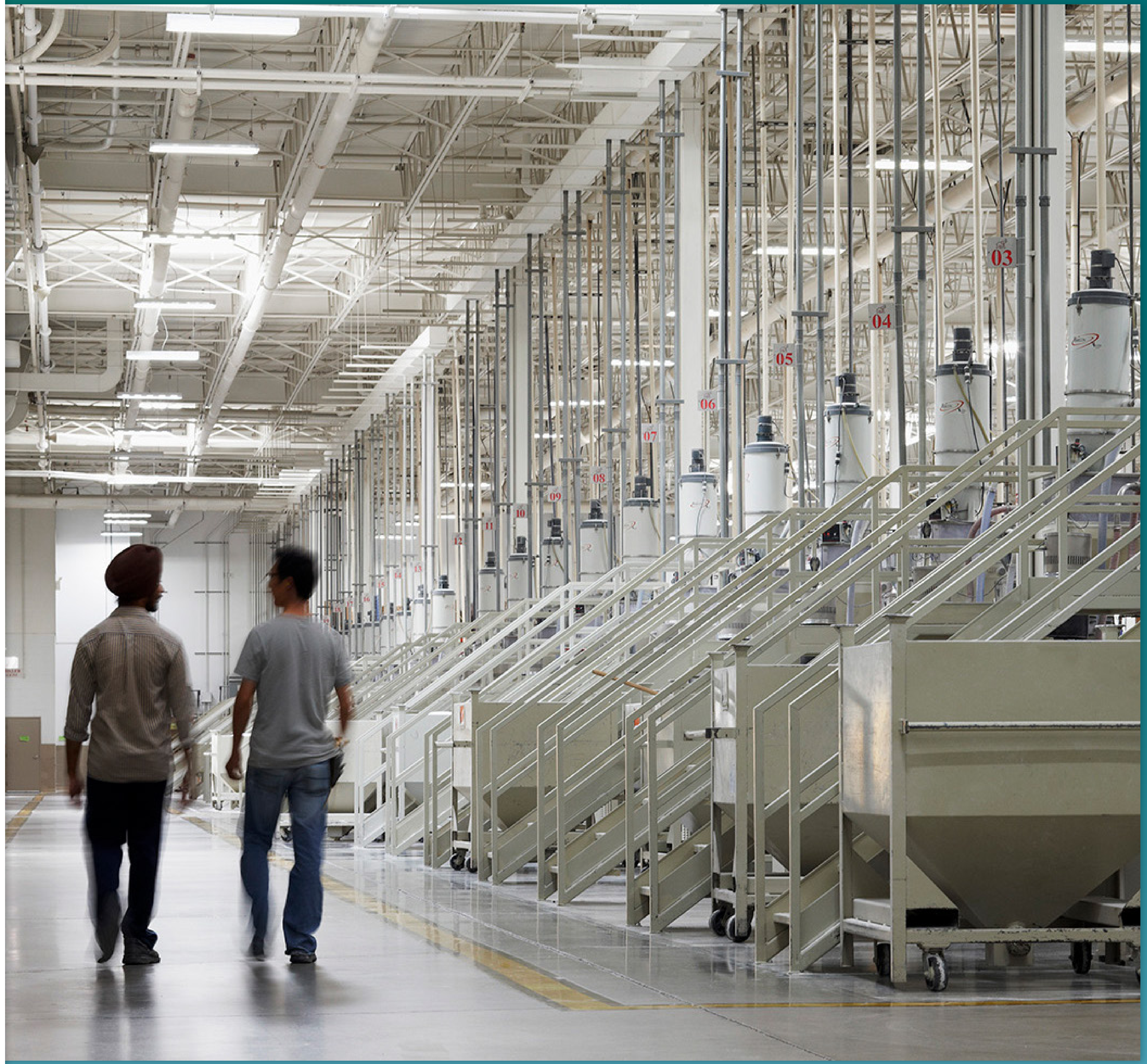
The Energy Manager program is the largest of its kind in North America, with trained energy-efficiency professionals helping large organizations save energy and drive Ontario's competitiveness

2019-2020 RESULTS:

195
Employed

46.6 GWh
Total Electricity Savings

5.0 MW
Total Demand Savings



Other specialized support for large energy consumers

Energy Performance Program:
performance-based incentives to drive change and deliver results

Process and Systems Upgrade:
support for complex industrial projects

Case Study:

Peel District School Board

The Energy and Sustainability department has been utilizing the Save on Energy incentive programs to help fund energy efficiency projects for several years, including the Energy Performance Program.

“The IESO’s energy incentive programs have helped PDSB reduce our energy costs and our carbon footprint, as well as make progress on our environmental and social equity goals.”

SHAHID NAEEM P.ENG. PMP
Manager, Energy & Sustainability
Peel District School Board

155,000
Students in kindergarten to grade 12

12 GWh
Total electricity savings over three years

259
Schools operate in the municipalities of Brampton, Caledon and Mississauga

Work included the installation of LED lighting, lighting controls and building automation system upgrades, among other things

41
Participating sites/buildings

Case Study:

Newmont Corp.

"With support from Save on Energy, we achieved an industry-first advanced electrification, and are on our way to eliminating diesel particulate matter from the underground environment. The project benefits will help us reduce energy costs and protect employee health while minimizing impacts to the environment."

JOHN MULLALLY
Country Manager and Senior Director, Sustainability and External Relations
Newmont Corp.

Borden's entire fleet of underground vehicles and heavy equipment will be either electric or battery-powered in place of conventional diesel-powered equipment and features state-of-the-art health and safety controls, and digital mining technologies and processes.

Located near Chapleau, Ontario, Newmont's Borden mine came into production in October 2019

Newmont received support from the IESO's Save on Energy programs

9 GWh

Expected annual energy savings resulting from an innovative "Ventilation On Demand" project that limits ventilation to when and where it is required

Home Assistance Program

Support for income-eligible consumers to reduce bills and increase home comfort with energy-saving upgrades at no cost to the participant

2019-2020 RESULTS:

22,859
Homes Supported

19.6 GWh
Total Electricity Savings

1.9 MW
Total Demand Savings

First Nations Conservation Program

Save on Energy offers First Nation communities specialized programs that reduce costs, improve home comfort and reduce reliance on fossil fuels

2019-2020 RESULTS:

823
Homes Supported

500 MWh
Total Electricity Savings

Support for Indigenous communities

Focused support for Indigenous communities through the First Nations Conservation Program and the Remote First Nation Energy Efficiency Pilot Program helps make electricity more affordable and improve health, safety and comfort

The Remote Pilot Program served four communities in 2019-2020:

- Kasabonika Lake First Nation
- Wunnumin Lake First Nation
- North Caribou Lake First Nation
- Sachigo Lake First Nation

12 more communities will be eligible in 2021

Local Program Fund

In addition to the suite of Save on Energy programs, communities are benefiting from tailored programming funded through the Local Program Fund and designed and delivered by local distribution companies. These programs help meet the needs of local areas and include incentives to businesses and residents for programs involving refrigeration, smart thermostats, block heater timers and more.

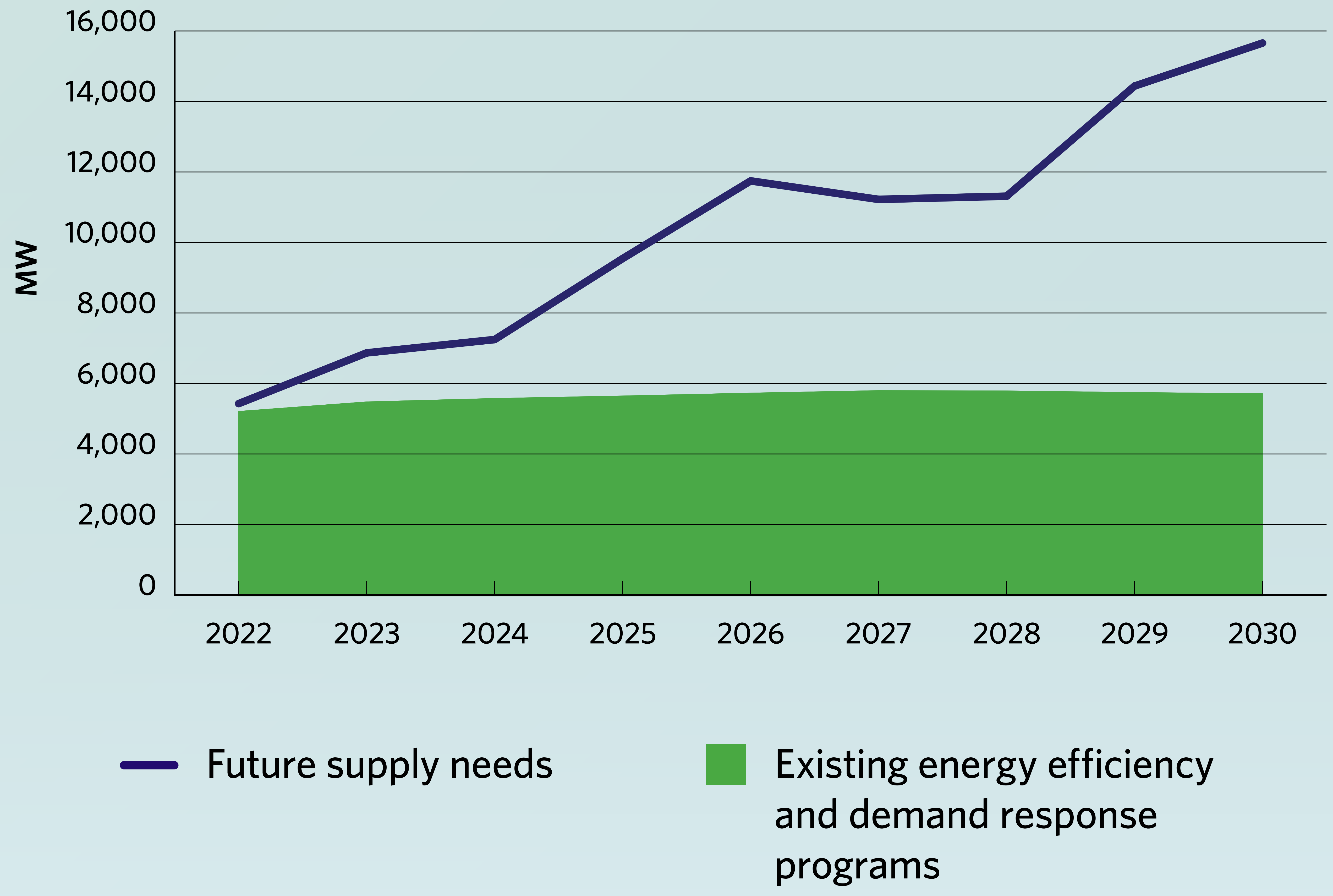
10

Local Programs Approved (2019-2020)

Why energy efficiency matters

At less than two cents per kilowatt-hour, it's Ontario's most cost-effective and enduring energy resource.

Consumers managing energy more efficiently will help address new supply needs with the potential for greater contributions as the IESO develops new approaches to energy efficiency.



Energy savings represented by the green shading is inclusive of the cumulative impacts from existing Save on Energy programs (including the current framework), Codes and Standards, Industrial Conservation Initiative (ICI), and other demand response programs.

Support for greenhouse owners

Energy efficiency is part of a broader solution to address increasing energy needs in southwestern Ontario.

The adoption of energy-efficient processes and technologies by businesses and communities has helped to reduce peak demand in the region by 10 MW.*

* Includes savings from 2015 Save on Energy programs and projects implemented with support from the IESO Grid Innovation Fund.

The current framework for energy efficiency

The IESO's 2021-2024 Conservation and Demand Management Framework will invest almost $700 million to reduce peak demand by 440 MW and consumption by 2.7 TWh.

2021-2024 CDM programs focus on those who need them most, including businesses, First Nation communities and Income-eligible residents.

The future of energy efficiency is rapidly evolving to:

- enable customer-focused solutions
- competitively procure energy efficiency to ensure cost-effectiveness
- respond to changing needs, particularly in vulnerable communities
- contribute to Ontario's post-pandemic economic recovery, particularly for small businesses
- deliver even greater electricity system resiliency and ratepayer value

Learn more today:

[Current Save on Energy programs]

First Nations Conservation Program

Ontario's energy needs

Energy Efficiency Auction

Grid Innovation Fund

Independent Electricity System Operator

Phone: 905.403.6900
Toll-free: 1.888.448.7777
Email: customer.relations@ieso.ca

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linkedin.com/company/ieso

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Save on Energy

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linkedin.com/company/saveonenergy-ontario

SaveOnEnergy.ca

ieso Connecting Today. Powering Tomorrow.

SAVE ON ENERGY POWER WHAT'S NEXT

Appendix:
Program Progress

Save on Energy programs contributed to 1.5 TWh of electricity savings and 186.4 MW of demand reduction from 2019 to 2020. The results demonstrate the value that energy efficiency provides for the electricity system and customers, and helps inform the future of conservation and demand management programs in the province. The data below includes customer participation and net-unverified contracted costs and savings. Totals include both committed and in-service project savings.

Final reported results will be provided later this fall with the posting of the Evaluation, Measurement and Verification (EM&V) reports. The EM&V process assesses the resource savings, cost-effectiveness and market impacts of each program. The reports will be available on the IESO website.

Program	Electricity Savings (GWh)	Demand Savings (MW)	Project Costs ($M)	Incentive Costs ($M)	Participation
Retrofit Program	1,187.9	144.7	47.7	145.3	11,128 projects
Small Business Lighting Program	47.2	11.6	3.7	11.2	6,826 projects
Energy Manager Program	46.6	5.0	1.3	14.0	195+ energy managers
Process and Systems Upgrade Program	196.5	20.2	4.7	46.0	106 projects
Energy Performance Program	9.9	1.2	0.4	1.1	22 facilities
Home Assistance Program	19.6	1.9	4.8	30.2	22,859 homes
Indigenous Programs	0.5	0.0	n/a	7.1	823 homes
Local Program Fund	8.7	1.8	n/a	18.0	44,779 projects*
IESO Central Services	n/a	n/a	18.0	n/a	
Total	**1,516.9**	**186.4**	**80.6**	**272.9**	
Interim Framework CDM Plan Target	**1,429.4**	**189.5**	**80.5**	**272.9**	
Actual vs. Target	**106%**	**98%**	**100%**	**100%**	

*756 projects from Refrigeration Efficiency Program, 42,621 homes from Community Conservation Program and 1,402 projects from Swimming Pool Efficiency Program

Changes to building codes and product standards help contribute to the province's conservation savings. These savings are covered in the IESO's Annual Planning Outlook.

Support for customers

In response to the COVID-19 pandemic, in-person interactions between Save on Energy representatives and customers were temporarily suspended on March 16, 2020, including visits to home and businesses. Participants of the Home Assistance Program, Small Business Lighting, and First Nations Conservation Program were placed on wait lists and were contacted for appointments once it was safe to visit homes and businesses. Participation targets set in the CDM Plan by program were impacted due to the ongoing pandemic, but overall, the IF energy targets were achieved. New programs under the 2021-2024 CDM Framework will continue to provide opportunities to help those who need them most and can contribute to reduced energy costs as businesses and residents recover from the impacts of COVID-19.

Learn more at saveonenergy.ca/en/FAQs

2021-2024 Conservation and Demand Management Framework

Update to 2021-2024 Conservation and Demand Management Framework Program Plan

The Conservation and Demand Management (CDM) Framework Program Plan is an overview of the CDM programs to be delivered by the IESO, under the Save on Energy brand, from January 2021 to December 2024. The plan sets out forecast budgets and, where applicable, savings targets and estimated cost-effectiveness for the portfolio of CDM programs.

The IESO reports on program participation, expenditures against budget, and progress towards demand and energy savings targets, greenhouse gas emission reductions, and additional achievements of the Energy Affordability Program and on-reserve First Nations programs, on an annual and quarterly basis. The IESO has undertaken a mid-term review of the framework; this updated plan reflects the actual spending and savings to date as well as the forecasted activity for the latter part of the framework, including the implementation of the new and enhanced initiatives planned as a result of the Minister's Amending Directive of October 4, 2022.

2021-2024 CDM Framework Overview

Electricity demand in Ontario is expected to grow rapidly in the coming years as a result of economic development and electrification of various sectors of the economy. At the same time, Ontario is seeing the retirement of generation assets resulting in growing system needs. In the midst of these needs, conservation demand management (CDM) initiatives will continue to offer ratepayer value as energy efficiency continues to be counted on as a clean, reliable and cost-effective approach to ensuring the reliability of the grid.

The current suite of programs was launched in 2021, following a directive from the Government of Ontario to develop a new four-year electricity CDM framework. The 2021-2024 CDM Framework focuses on cost-effectively meeting the needs of electricity consumers and Ontario's electricity system through the delivery of programs and opportunities to enable electricity consumers – including industrial, commercial, institutional, on-reserve First Nations, low-income and income-eligible residential consumers - to improve the energy efficiency of their homes, businesses and facilities.

Since the launch of the framework in 2021, the government has taken additional action with a directive to enhance the 2021-2024 Framework. The IESO is pursuing enhancements to various Save on Energy programs (including those focused on income-eligible and First Nations customers) to address system and customer needs. This includes moving forward to launch four new or enhanced CDM programs in 2023 to increase energy efficiency contributions to emerging system needs.

Additional focus areas of the framework include:

- Achieving provincial peak demand reductions and implementing targeted approaches to address regional/local system needs using demand-side solutions as cost-effective alternatives to traditional infrastructure investments
- Leveraging competitive mechanisms to drive cost efficiencies and support innovative customer-based solutions.

Details about the various incentives offered through each program and how to apply is available at SaveOnEnergy.ca.

Budget and Targets:

The plan, which is subject to changes and revisions over time, allocates the 2021-2024 Conservation and Demand Management Framework budget of up to $1.034 billion over the suite of programs and is forecasted to achieve 725 MW of peak demand savings and 3.8 TWh of electricity savings by 2026. These savings are expected to persist for 10 to 20 years from the implementation of the measure.

Reporting:

As part of its responsibilities, the IESO will publish the verified results of its evaluation, measurement and verification (EM&V) of the savings resulting from the 2021-2024 CDM Framework, as well as costs related to its activities in support of the programs such as audits, capability building and training. The IESO will publish verified program results on an annual basis, as well as quarterly program updates, to inform the sector on the progress to meeting the targets. The 2021 Verified Results are available at IESO.ca.

Cost Effectiveness:

Program cost-effectiveness under the 2021-2024 CDM Framework for the CDM Plan is assessed using forecasted program participation and supply-side avoided costs, which estimate the cost of supplying that same amount of energy from the current electricity generation mix. The IESO Cost-Effectiveness Guide is available on the IESO website. Cost effectiveness in this plan is based on avoided supply costs developed in the IESO's 2021 Annual Planning Outlook and has been updated to reflect changes in the province's planning outlook.

2021-2024 CDM Framework Summary Tables:

The following tables outline the associated budget, electricity and demand savings, and cost-effectiveness of the programs delivered under the 2021-2024 CDM Framework.

Budget

Program	Budget ($M)			
	2021	2022	2023	2024
Retrofit Programs	57.3	78.7	93.9	122.1
Small Business	4.1	1.8	6.8	15.8
Energy Performance	2.2	2.1	8.3	8.4
Energy Management	0.4	7.0	6.0	13.6
Industrial Energy Efficiency	0.0	0.0	29.0	41.0
Targeted Greenhouse	0.0	0.0	68.0	68.0
Local Initiatives	0.0	0.0	69.6	70.1
Residential Demand Response	0.0	0.0	10.3	14.6
Total Business & Residential Programs	**64.0**	**89.6**	**291.8**	**353.5**
Energy Affordability Program	10.8	13.8	41.7	87.0
First Nations Programs	1.3	0.1	18.1	16.4
Total Support Programs	**12.0**	**13.9**	**59.8**	**103.4**
Total All Programs	**76.0**	**103.5**	**351.7**	**456.9**
Customer Education and Tools	0.0	0.3	0.4	0.5
Central Services -- Business	2.7	4.3	17.3	17.6
Central Services -- Support	0.0	0.2	1.3	1.3
Total IESO Services	**2.7**	**4.8**	**19.0**	**19.4**
Total Annual Budget	**78.7**	**108.3**	**370.7**	**476.3**
CDM Framework Total				**1,034.0**

Peak Demand and Energy Savings

Program	Peak Demand Savings (MW) 2021	2022	2023	2024	Energy Savings (GWh) 2021	2022	2023	2024
Retrofit Programs	49.5	89.8	96.5	127.9	322	570	359	560
Small Business	1.5	0.6	3.0	9.0	10	4	20	65
Energy Performance	1.8	1.8	8.4	8.4	16	20	50	54
Energy Management	0.1	1.8	8.0	25.1	1	15	29	96
Industrial Energy Efficiency	0.0	0.0	20.0	22.0	0.0	0.0	165	165
Targeted Greenhouse	0.0	0.0	1.4	1.3	0.0	0.0	333	333
Local Initiatives	0.0	8.0	43.0	45.4	0.0	61	161	181
Residential Demand Response	0.0	0.0	84.0	123.0	0.0	0.0	3	7
Total Business & Residential Programs	**52.9**	**101.9**	**264.3**	**362.1**	**349**	**670**	**1,120**	**1,462**
Energy Affordability Program	0.7	1.1	7.5	14.5	7	14	49	97
First Nations Programs	0.0	0.0	2.0	2.0	1	0	15	16
Total Support Programs	**0.7**	**1.1**	**9.5**	**16.5**	**8**	**14**	**64**	**113**
Total Annual Savings	**53.6**	**103.0**	**273.8**	**378.6**	**357**	**684**	**1,184**	**1,575**
CDM Framework Total				**725.0**				**3,800**

*Values may not add up precisely due to rounding

Notes:

- 2022 values are estimates based on available preliminary results and forecasts
- For Residential Demand Response the Peak Savings value is the estimated peak demand impact for the year of operation and does not persist over time. The Total Peak Demand Savings of 725 MW includes the Residential Demand Response peak impact only in 2024 to avoid double counting of savings.
- Retrofit Programs include: Retrofit Prescriptive, Midstream Lighting, Custom Lighting, and Custom Non-Lighting

- Energy Management Programs include: Energy Manager Program, Strategic Energy Management, and Existing Building Commissioning
- Targeted Greenhouse is estimated to provide 2.7 MW of provincial peak demand reduction while also reducing the Southwestern Ontario local peak demand by approximately 225 MW
- Local Initiatives include: Local Initiatives and Enhanced Local Initiatives

Program Cost-Effectiveness

	Cost Effectiveness		
Program	**Program Administrator Cost (PAC) Ratio**	**Levelized Unit Energy Costs ($/MWh)**	**Levelized Unit Capacity Costs ($'000/MW-yr)**
Retrofit Programs	2.3	25	126
Small Business	1.2	39	308
Energy Performance	2.7	20	138
Energy Management	1.6	39	143
Industrial Energy Efficiency	1.9	28	218
Targeted Greenhouse	2.3	21	n/a
Local Initiatives	1.6	41	173
Residential Demand Response	1.0	n/a	112
All Business & Residential Programs	**2.0**	**27**	**144**

Technical Notes:

- Peak demand savings are calculated in accordance with the IESO Evaluation, Measurement and Verification Protocols and Requirements. Peak demand savings and energy savings persist to 2026 and assumes the Residential Demand Response program will continue beyond the current Framework.
- Budgets are funds committed in the calendar year; energy and demand savings in a calendar year are those resulting from the budget commitment.
- Cost effectiveness is calculated in accordance with the IESO's Cost Effectiveness Guide. Avoided supply costs are based on the IESO's 2021 Annual Planning Outlook and has been updated to reflect changes in the province's planning outlook.
- As per the September 30, 2020, Ministerial Directive, the Support Programs are not required to meet cost-effectiveness thresholds as these programs provide significant non-energy benefits not captured through cost-effectiveness analysis.

Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts

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Clearspring Energy Advisors LLC

Contents

1 Executive Summary

Toronto Hydro-Electric System Limited ("Toronto Hydro" or "Company") engaged Clearspring Energy Advisors, LLC ("Clearspring") to develop a model ("Integration Model") that integrates the Company's revenue forecast for the years 2025 to 2029 with forecasts for electric vehicles ("EVs") and distributed energy resources ("DERs"). The lead model developer is Mr. Steven A. Fenrick. Mr. Fenrick has developed models, provided research reports, and expert witness testimony before the Ontario Energy Board in several applications including Toronto Hydro's previous distribution rate application. Mr. Fenrick and Clearspring have been involved in several load forecasting studies. In recent years, many of these studies have begun to incorporate EV and DER forecasting into the analysis. A copy of Mr. Fenrick's summary *curriculum vitae* is attached in Appendix B.

The objective of the Integration Model is to forecast the impact on energy and billing demand by rate class resulting from the forecasted changes in EVs and DERs. Clearspring also produced an analysis on the changes to the rate class load profiles resulting from the EV and DER forecasts that is used as an input in the cost allocation model by Toronto Hydro for rate setting purposes.

The base revenue forecast is produced by Toronto Hydro. Toronto Hydro also provided Clearspring with the historical data and forecasts for the number of EVs and the nameplate capacity of DERs on its system along with other assumptions on EV consumption and DER production. Clearspring's research focused not on the EV and DER forecasts themselves but rather on building a model that estimates the impacts of those forecasts onto the billing determinants of energy and demand.

The Integration Model and the forecasted impact of the technologies onto the base revenue forecast is discussed in Sections 1 through 8. Please see Section 9 for a summary of the cost allocation model ("CAM") analysis.

1.1 Forecast Inputs

Electric vehicles and distributed energy resources are emerging technologies that have the potential to significantly influence the energy delivered by utilities and the peak demands they need to plan for. The overall impact on the kilowatt hours ("kWhs") and the timing of charging or production is relevant for forecasting the energy and demand billing determinants. EVs will increase electricity consumption and demand, whereas DERs will tend to decrease them.

Our study uses the following forecast inputs, provided by Toronto Hydro, to forecast the impacts of EVs and DERs onto the billing components of energy and demand:

1. Light-duty electric vehicles ("LDEVs")
2. Medium-duty electric vehicles ("MDEVs")
3. Heavy-duty electric vehicles ("HDEVs")
4. Customer-owned ground-mounted and roof-mounted solar photovoltaic panels ("Renewables")
5. Customer-owned non-renewable distributed energy resources ("Non-Renewable")

6. Customer-owned energy storage resources

The base revenue forecast is produced and was provided to Clearspring by Toronto Hydro's staff.[1] It is Clearspring's understanding that the dataset used to inform the econometric models of the base forecast has an end year of 2023. Therefore, the Integration Model estimates the incremental load of these technologies from their 2023 adoption levels to the forecasted levels of the future custom incentive regulation years of 2025 to 2029.

The incremental energy and billing demand from 2023 of LDEVs, MDEVs, HDEVs, Renewable, Non-Renewable DER, and energy storage are forecasted by the Integration Model and are to be added to the base revenue forecast. The technology forecasts are required because these technologies are expected to exceed historical market adoption levels. Given this anticipated acceleration, the base revenue forecast does not satisfactorily account for the anticipated future load impacts of these technologies.

1.2 Forecast Summary of EVs and DERs

The six technology inputs can be aggregated to the base revenue forecast to determine the expected forecast after accounting for these technologies. There is a balancing of impacts between the technologies as EVs will increase energy and billing demand, whereas DERs will lower energy and billing demand.

The net forecasted impacts as a percentage of the base revenue forecast on a total system basis are provided below annually.[2] Please see Appendix A for monthly breakdowns of the energy and billing demand impacts of the technology forecasts by rate class.

Table 1: Annual Forecasted Energy and Billing Demand Impacts

Year	Incremental Energy (kWh) % Increase	Incremental Billing Demand (kVA) % Increase
2025	-0.1%	-0.3%
2026	0.3%	-0.1%
2027	0.8%	0.2%
2028	1.4%	0.6%
2029	2.1%	1.0%

The net impacts are forecasted to have a minimal impact on the base revenue forecast in 2025 but this impact is projected to increase to 2.1% for energy and 1.0% for billing demand by 2029 as EV technologies mature and market adoption accelerates.

[1] The base forecast results and methodology are described in Exhibit 3.

[2] The forecasts are integrated monthly as the base revenue forecast is monthly, but we display annual impacts here for display purposes.

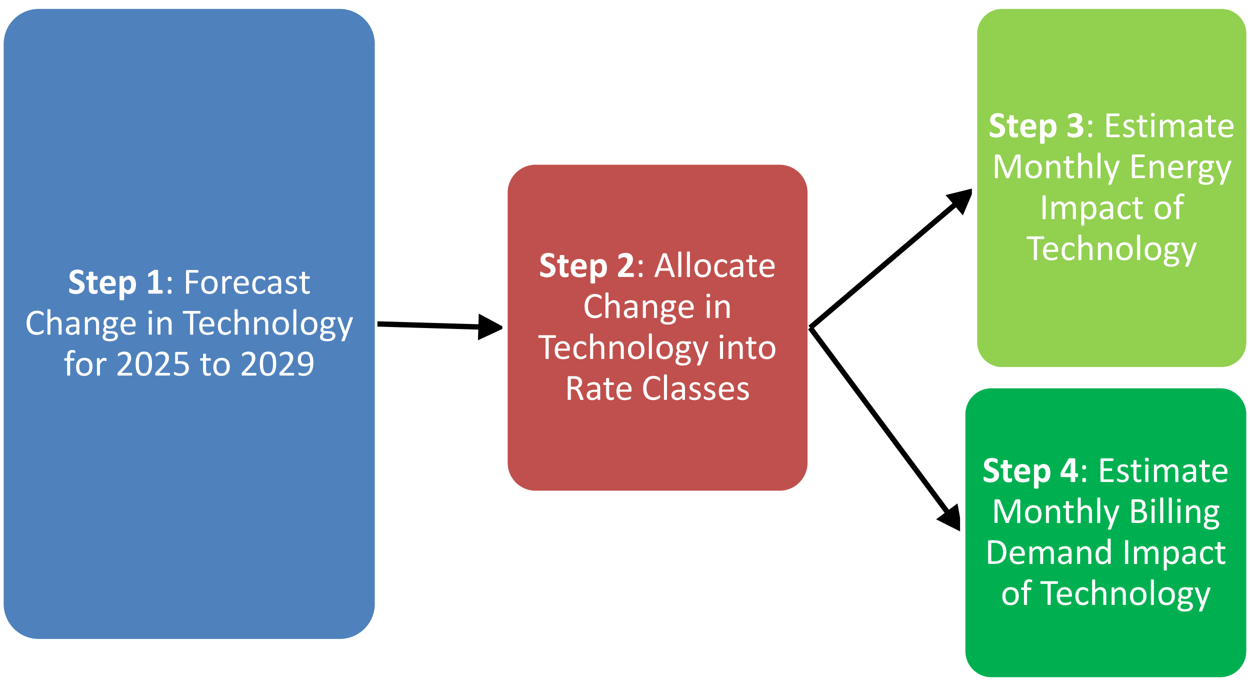
2 Integration Forecast Methodology

The 2025-2029 forecasts for the EV counts and DER nameplate capacities are provided by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs and renewable resources.

After being provided with the forecasts for the technology counts/capacities on a system-wide basis, the Integration Model undertakes a four-step process to translate the forecasted technology count/capacity into incremental energy and billing demand.

The four steps are:

1. Calculate the change in the count/capacity forecasts from 2023.
2. Allocate the change from 2023 to a specific rate class.
3. Estimate the monthly energy (kWh) impact of each technology for the rate class in 2025 through 2029.
4. Estimate the billing demand (kVA) impact of each technology for the three rate classes that contain a billing demand component in 2025 through 2029.



2.1 Forecast Change in Technology Count

The objective of the research is to forecast how much energy and billing demand should be added to the base revenue forecast to account for the changes in the technologies included in the study. The base revenue forecast sample dataset goes through the year 2023. The load effects for each technology through 2023 will be embedded within the data used to calculate the base forecasting models.

It is, therefore, the incremental loads from their 2023 values that will drive a change to the base revenue forecast for the upcoming years of 2025 to 2029. The Integration Model calculates the change in each technology for these upcoming years from the 2023 value. These new loads will drive an incremental change in energy and billing demand to the base revenue forecast.

2.2 Allocate Incremental Change to the Rate Classes

Integrating the technology forecasts with the revenue forecast requires allocating the technology count/capacity into appropriate rate classes. The six rate classes that we allocated EVs and DERs to are:

- Residential
- CSMUR
- GS<50 kW
- GS50-999 kW
- GS 1-5 MW
- Large Use

Three of the rate classes also have a billing demand component that is calculated based on the customer's highest kVA reading during the month. The three classes with a demand rate component are the larger customer classes of GS50-999 kW, GS 1-5 MW, and Large Use. For these three rate classes, the Integration Model forecasts the impact on billing demands from the incremental additions of EVs and DERs using hourly interval data specific to individual customers within each rate class and layered on technology hourly load profiles to estimate the impact on billing demand resulting from the presence of the technology. This process is discussed further below in Step 4.

Technologies were allocated by the Integration Model to rate classes based on where the technology is most likely to be used and installed. LDEVs are more likely to be owned and charged at residences and have higher concentrations in the residential rate class, whereas HDEVs are more likely to be owned and charged at larger businesses and be concentrated in the general service or Large Use rate classes.

The following list summarizes the technology and the information used in the Integration Model to allocate each technology to the six rate classes.

Technology	Rate Class Allocation Method
Light-Duty EVs (LDEVs)	The Integration Model uses an estimate of 91% of home charging, placing 91% of LDEVs in the residential rate class.[3] The remaining 9% was apportioned to the other five rate classes based on the percentages of Level 2 EV chargers at Toronto Hydro.
Medium-Duty EVs (MDEVs)	The Integration Model uses the rate class percentage of kWh usage in the Manufacturing and Warehouse industry sector at Toronto Hydro.
Heavy-Duty EVs (HDEVs)	Same as the MDEV method but TTC kWh usage is added to the percentages.
Renewable DER	The Integration Model uses Toronto Hydro's records of customers on the net metering program and the installed kW capacity of Solar by rate class.
Non-Renewable DER	The Integration Model uses the current Non-Renewable installed nameplate capacity by rate class at Toronto Hydro.
Energy Storage	The Integration Model uses the current energy storage by nameplate capacity by rate class.

2.3 Estimate Monthly Energy Impact

Estimating the energy contribution of each technology by month to each rate class involves multiplying the expected energy required to charge the EV (or the expected production of the DER) in each month by the forecasted number of EVs/DERs in each rate class. The energy usage for EVs will vary due to temperatures impacting the battery efficiencies of the vehicles. Cold temperatures reduce battery efficiency relative to milder temperatures. The Integration Model uses a differential assumption of +/- 10 percent to adjust for this reality.[4] [5] Renewable DERs tend to produce far more energy in the summer months when sunlight is more direct than during winter months. The Integration Model inputs capacity factors for Renewables that are specific to winter and summer months. The model makes no seasonal adjustment for Non-Renewable DERs.

The average daily EV energy consumption was provided by Toronto Hydro. For LDEVs, Toronto Hydro estimated an average daily consumption of 9.4 kWh per LDEV. For MDEVs, Toronto Hydro estimated

[3] USDRIVE, Summary Report on EVs605 at Scale and the U.S. Power System, Grid Integration Tech Team and Integrated Systems Analysis Tech Team, 2019.

[4] Cold Temperatures Affect an Electric Vehicle's Driving Range - Consumer Reports

[5] May through September are designated as summer months and are reduced by 10 percent and the remaining months designated as winter months and are increased by 10 percent.

103.56 kWh per MDEV use per day. For HDEVs, Toronto Hydro estimated 319.87 kWh per HDEV use per day. Clearspring then multiplied these daily estimates by the number of days in each month and adjusted for summer/winter seasonal differences.

The Renewable and Non-Renewable average hourly capacity factors are provided by Toronto Hydro. The capacity factors are summed to estimate the daily energy production. This daily production is multiplied by the number of days in each month. The Renewable capacity factors are specific to summer and winter. Energy storage is assumed to not be actively charged and discharged, due to a current lack of evidence regarding how energy storage may be used at customer sites, and so will not have an impact on the results.

2.4 Estimate Monthly Billing Demand Impact

Three of Toronto Hydro's rate classes are billed on peak demand,[6] which is calculated as the highest kVA demand for that customer in each month. Billing demand times and amounts will vary from customer to customer and from month to month. The presence of EV charging will put upward pressure on billing demand and that pressure is a function of the number of EVs being charged at the premise, the load profiles of those EVs, and the base load profile for that customer. DERs will also have an impact on billing demand, but in the opposite direction. However, the mechanics of forecasting the change in the Integration Model are the same.

The Integration Model accounts for these factors by using hourly load profiles of the EVs and hourly capacity factors of the DERs, receiving smart meter hourly interval data for customers from Toronto Hydro from the three rate classes with a billing demand component, and then examining how the estimated number of EVs or DERs would impact billing demand for each general service customer. A load profile that estimates the hourly charging requirements (or production expectations) of an EV/DER at the general service customer premise is necessary for the analysis.[7] The load profiles are based on either Toronto Hydro analysis or external sources and are scaled to match the energy assumptions found in Step 3.[8]

[6] These rate classes are GS 50-999, GS 1-5MW, and Large Users. The remaining rate classes do not have a billing demand rate component.

[7] Since only the three general service rate classes have a billing demand component, it is only a general service load profile that needs to be calculated. Residential home charging can be ignored when estimating billing demand impacts.

[8] The LDEV hourly profile was derived from the U.S. Department of Energy Alternative Fuels Data Center. More details on the LDEV hourly profiles are provided in Section 3. The MDEV, HDEV, and DER hourly load profiles are provided by Toronto Hydro.

The following table shows the seasonal hourly load profiles used for each EV technology in the billing demand analysis of Step 4.

Table 2: Seasonal Hourly Load Profiles by EV Technology

Hour Beginning	Summer LDEV	Winter LDEV	Summer MDEV	Winter MDEV	Summer HDEV	Winter HDEV
0	0.0	0.1	4.0	4.9	29.0	35.4
1	0.0	0.0	4.1	5.0	25.2	30.8
2	0.0	0.0	3.7	4.5	19.4	23.7
3	0.0	0.0	4.4	5.3	14.8	18.0
4	0.1	0.1	4.1	5.0	14.2	17.3
5	0.1	0.2	3.6	4.4	12.1	14.8
6	0.4	0.5	3.2	3.9	12.8	15.6
7	0.9	1.1	2.9	3.5	11.9	14.6
8	1.3	1.6	0.9	1.0	2.4	3.0
9	1.3	1.5	1.0	1.2	8.7	10.6
10	0.9	1.1	1.8	2.2	10.5	12.8
11	0.7	0.8	2.1	2.5	13.7	16.7
12	0.5	0.6	4.1	5.0	11.7	14.3
13	0.4	0.5	3.7	4.5	10.3	12.6
14	0.4	0.1	3.6	4.4	10.9	13.4
15	0.4	0.4	4.8	5.8	9.5	11.6
16	0.3	0.4	5.7	7.0	9.2	11.2
17	0.2	0.3	5.2	6.3	8.8	10.7
18	0.2	0.2	4.9	6.0	6.4	7.8
19	0.1	0.1	5.0	6.1	5.8	7.1
20	0.1	0.1	5.8	7.1	4.4	5.4
21	0.1	0.1	5.8	7.1	4.0	4.9
22	0.1	0.1	5.1	6.3	3.3	4.0
23	0.0	0.1	4.0	4.9	29.0	35.4

The following table displays the capacity factors for the DERs. A value of -0.5 means that the model assumes the DER will produce 0.5 kWh for every 1 kW of nameplate capacity in that hour.[9]

Table 3: Seasonal DER Capacity Factors

Hour Beginning	Solar Summer	Solar Winter	Energy Storage Summer	Energy Storage Winter	Non-Renewable Summer	Non-Renewable Winter
0	0	0	0	0	-0.66	-0.66
1	0	0	0	0	-0.65	-0.65
2	0	0	0	0	-0.65	-0.65
3	0	0	0	0	-0.65	-0.65
4	0	0	0	0	-0.65	-0.65
5	0	0	0	0	-0.65	-0.65
6	0	0	0	0	-0.66	-0.66
7	-0.03	-0.01	0	0	-0.67	-0.67
8	-0.13	-0.02	0	0	-0.67	-0.67
9	-0.22	-0.04	0	0	-0.67	-0.67
10	-0.28	-0.05	0	0	-0.67	-0.67
11	-0.32	-0.06	0	0	-0.67	-0.67
12	-0.33	-0.06	0	0	-0.67	-0.67
13	-0.35	-0.07	0	0	-0.67	-0.67
14	-0.34	-0.06	0	0	-0.68	-0.68
15	-0.33	-0.06	0	0	-0.68	-0.68
16	-0.32	-0.06	0	0	-0.68	-0.68
17	-0.28	-0.05	0	0	-0.67	-0.67
18	-0.2	-0.04	0	0	-0.67	-0.67
19	-0.09	-0.02	0	0	-0.67	-0.67
20	0	0	0	0	-0.67	-0.67
21	0	0	0	0	-0.66	-0.66
22	0	0	0	0	-0.66	-0.66
23	0	0	0	0	-0.66	-0.66

The Integration Model inputs 2019 hourly smart meter data for customers in the three rate classes with a billing demand component. The year of 2019 is used since 2020 and subsequent hourly load data was influenced by the Covid-19 pandemic. Using this data provides 8,760 hourly observations for each customer included in the analysis. For the rate classes of GS 1-5MW and Large Use, Clearspring received and processed the 2019 interval data for all the customers in the rate classes. Given the large number of customers in the GS 50-999 rate class, Clearspring extracted a sample of the data for that rate class to conduct the billing demand impact analysis.

Using the hourly interval data, the monthly billing demands in 2019 can be calculated for every customer in the three samples. The Integration Model adds the technology load profile to the customer load profile

[9] We assume zero for energy storage as there is not yet evidence available on if energy storage will be used to avoid billing demand or other peak demands or only be used for resiliency.

in every single hour of the year. The revised customer load profile with the new technology loads added is used to calculate what the billing demand would have been if the technology had been present for each customer.

The before and after billing demand differences for every customer are averaged in each rate class to produce an estimate of how much billing demand is predicted to change from adding the technology at the customer premise. This is used to produce the average kW impact per EV (or per DER nameplate) in each month. The average kW estimate is multiplied by the forecasts for the technology count/capacity in each rate class to determine the kW impacts for each rate class by each month. The kW estimate impacts are escalated by an assumption of a 0.95 power factor to translate from kW to kVA.[10]

Layering estimated technology load profiles to customer hourly interval data enables the analysis to adjust for when each customer is actually consuming its peak demand for the month, since customers incur their billing peaks at varying times of day. This procedure enables the model to estimate how the technology will influence the load that is specific to that specific customer's peak time. This is important since EVs are not charged uniformly through the day, nor do Renewable DERs have a constant production curve.

The second advantage of this procedure is that it gives the model flexibility to adjust the peak time after the new loads are added. The addition of EV load (or DER production) may move the peak time to an entirely different hour and the analysis accounts for this possibility.[11]

The steps in the billing demand analysis can be summarized as follows:

1. Estimate the technology hourly load profile.
2. Process the 2019 hourly interval customer data in each of the three rate classes.
3. Calculate the average billing demand in each rate class in 2019.
4. Add the technology hourly load profiles to the customer hourly interval data for every hour in the year.
5. Calculate the average billing demand in each rate class after the addition of the technology hourly load profiles.
6. Take the difference in the before and after billing demand to estimate a per unit billing demand impact for the technology.
7. Multiply the per unit billing demand impact for the rate class by the forecasted number of EVs or DER nameplate capacity for that rate class.

[10] This assumption was provided to Clearspring from Toronto Hydro.

[11] The more EVs or DER capacity at a given customer site, the more likely it will be that the presence of the technology will shift the billing peak time to a different time that day or to a separate day. The Integration Model accounts for this by adding more EVs and more DER capacity for the larger rate class customers (GS 1-5 MW and Large Use) who are likely to have a higher number of EVs or DERs on site than those customers GS 50-999 kW.

3 Light-Duty Electric Vehicle Forecasts

Vehicles classified as Light-Duty Vehicles ("LDVs") weigh less than 4,535 kilograms according to Statistics Canada. There are two major types of Light-Duty Electric Vehicles ("LDEVs") on the market today: battery electric vehicles ("BEV") and plug-in hybrid electric vehicles ("PHEV"). For the purposes of the Integration Model, we do not distinguish between these two types of LDEVs. Given that most driving and the necessary charging will occur due to relatively short driving distances in or near the City of Toronto, both BEVs and PHEVs will add similar electric demand profiles to the grid.

The market adoption rate of LDEVs has grown but continues to be low relative to future expectations. The maturation of the technology, decreasing prices relative to internal combustion engines ("ICE"), and increasing charging opportunities are increasing sales of EVs as a percentage of total sales. However, recent supply chain issues caused by COVID have slowed down adoption rates.[12]

The LDEV forecast was provided by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs.[13] Historic LDEV data was estimated by Toronto Hydro and is small compared to the future forecasts of LDEVs.

The electric vehicles will mostly be charged at the owner's residence. However, some of the LDEVs will be charged at alternate locations, typically at the place of work. The energy required for home charging will add to residential energy use and the alternate locational charging will add to the general service rate classes. Integration of the LDEVs into the revenue forecast requires an assumption on the rate class split of where charging will occur.

The Integration Model assumes 91% of LDEV charging in Toronto will occur at home.[14] The remaining 9% of LDEV charging is allocated to the other five rate classes based on Toronto Hydro data on the percentage of Level 2 EV chargers in those five rate classes.

For display purposes, the following table displays the annual LDEV counts for each rate class after allocating 91% to the residential class and divvying up the remaining 9% based on Level 2 EV chargers. The

[12] 'Unprecedented' global chip shortage pushing electric vehicle delays into years - National | Globalnews.ca.

[13] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=48-AEO2023&cases=ref2023&sourcekey=0.

[14] USDRIVE, Summary Report on EVs605 at Scale and the U.S. Power System, Grid Integration Tech Team and Integrated Systems Analysis Tech Team, 2019.

model is, however, monthly, with the LDEV counts escalating to the annual numbers in December of each year.

Table 4: Number of LDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2019	6,772	43	143	342	128	14
2020	9,023	57	190	456	171	19
2021	11,960	76	252	604	227	25
2022	19,520	123	411	986	370	41
2023	29,972	189	631	1,514	568	63
2024	43,635	275	918	2,204	826	92
2025	59,429	375	1,251	3,001	1,126	125
2026	76,411	482	1,608	3,859	1,447	161
2027	96,006	606	2,020	4,849	1,818	202
2028	117,339	741	2,469	5,926	2,222	247
2029	140,303	886	2,952	7,086	2,657	295

3.1 LDEV Energy Forecast

Estimating the energy contribution of each LDEV by month for each rate class involves multiplying the expected energy required to charge each LDEV in each month by the forecasted number of LDEVs in each rate class. The charging energy required is a function of the average kilometres ("km") driven each day and the average EV efficiency factor. The EV efficiency factor measures how many kilowatt hours ("kWh") of electricity are required per kilometre of driving.

$$kWh\ per\ day\ for\ LDEV = average\ km\ driven\ per\ day\ (km) * EV\ efficiency\ factor\ (kWh\ /\ km)$$

Toronto Hydro estimated that an average Toronto LDEV driver will average 40.3 km/day. The EV efficiency factor is estimated by Toronto Hydro at .233 kWh/km. Multiplying these two components together produces the estimate of each LDEV requiring 9.4 kWh per day, which appears reasonable to Clearspring based on our experience and other external sources.[15]

[15]https://ecocostsavings.com/average-electric-car-kwh-per-mile/.

The following table displays the forecasted annual LDEV energy contribution for each rate class.

Table 5: Annual LDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2019	2,168,435	13,689	45,630	109,512	41,067	4,563
2020	27,822,885	175,641	585,471	1,405,131	526,924	58,547
2021	36,954,088	233,285	777,617	1,866,281	699,855	77,762
2022	55,886,731	352,804	1,176,013	2,822,430	1,058,411	117,601
2023	87,660,678	553,387	1,844,625	4,427,100	1,660,162	184,462
2024	130,109,415	821,359	2,737,865	6,570,875	2,464,078	273,786
2025	181,707,014	1,147,087	3,823,622	9,176,693	3,441,260	382,362
2026	238,948,815	1,508,445	5,028,149	12,067,558	4,525,334	502,815
2027	303,011,373	1,912,861	6,376,204	15,302,889	5,738,583	637,620
2028	374,527,806	2,364,333	7,881,109	18,914,661	7,092,998	788,111
2029	451,895,366	2,852,741	9,509,138	22,821,931	8,558,224	950,914

The forecasts are translated into monthly forecasts using the monthly LDEV counts found in Table 4 and multiplying the average daily kWh charging by the number of days in each month. An additional monthly adjustment is made to account for the reality that EV batteries perform worse in cold temperatures.[16] To adjust for this, the Integration Model adds 10 percent to the energy totals in winter months and subtracted 10 percent to the energy totals in summer months.[17]

To integrate the LDEV forecasted energy into the revenue forecast, the incremental load of LDEVs for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental load in each month in 2025 to 2029 is the difference between that month's forecasted LDEV load and the same month in 2023.

For display purposes, the following table displays the annual LDEV incremental energy impact from 2023 levels for each rate class. The model is, however, monthly. Also shown is the average increase in LDEV energy from the base revenue forecast for each rate class.

Table 6: Annual Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	94,046,336	593,699	1,978,997	4,749,593	1,781,097	197,900
2026	151,288,137	955,057	3,183,524	7,640,458	2,865,172	318,352
2027	215,350,695	1,359,474	4,531,579	10,875,789	4,078,421	453,158
2028	286,867,128	1,810,945	6,036,484	14,487,561	5,432,835	603,648
2029	364,234,688	2,299,354	7,664,513	18,394,831	6,898,062	766,451

[16] https://cleantechnica.com/2022/12/19/how-temperature-affects-electric-car-range-charging-performance/.

[17] Summer months are defined as May through September with the remaining months designated as winter months.

3.2 LDEV Billing Demand Forecast

A load profile that estimates the hourly charging requirements of an LDEV at the general service customer premise is necessary to forecast the impact of LDEVs on billing demand.[18] Most of this charging will be from commuters who are working at the place of business. The Integration Model uses a load profile that estimates "at work" charging behavior per LDEV from the U.S. Department of Energy (DOE) Alternative Fuels Data Center.[19]

The DOE profile is scaled to match the LDEV energy charging assumptions that were provided to Clearspring by Toronto Hydro. The model scales the profile to match the energy use estimate of 9.4 kWh and adjusts for summer and winter differences in battery efficiency. The winter and summer LDEV load profiles for "at work" charging used in the analysis are provided in the following table.

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[18] Since only the three general service rate classes have a billing demand component, it is only a general service load profile that needs to be calculated. Residential home charging can be ignored when estimating billing demand impacts.

[19] The DOE profile tool can be found here: https://afdc.energy.gov/evi-pro-lite/load-profile/. The profile used a location of Chicago, which is also on a Great Lake and has similar weather to Toronto, and 25 commuting miles.

Table 7: Summer and Winter LDEV Work Charging Load Profile

Hour	Summer LDEV Load	Winter LDEV Load
0	0.04	0.05
1	0.03	0.04
2	0.03	0.03
3	0.02	0.02
4	0.05	0.06
5	0.14	0.18
6	0.41	0.50
7	0.88	1.08
8	1.33	1.62
9	1.25	1.53
10	0.94	1.15
11	0.65	0.80
12	0.47	0.57
13	0.42	0.52
14	0.40	0.14
15	0.35	0.43
16	0.29	0.35
17	0.22	0.27
18	0.16	0.19
19	0.12	0.14
20	0.08	0.10
21	0.06	0.07
22	0.05	0.07
23	0.05	0.06

For display purposes, the following table displays the annual LDEV incremental billing demand impact from 2023 levels for each rate class. The model is, however, monthly.

Table 8: Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	10,594	4,076	412
2026	17,043	6,557	663
2027	24,260	9,334	944
2028	32,316	12,434	1,258
2029	41,032	15,788	1,597

Shown in the following table is the average percentage increase in LDEV billing demand from the base revenue forecast for each rate class.

Table 9: LDEV Percentage Increase from Base Demand by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%
2026	0.1%	0.1%	0.0%
2027	0.1%	0.1%	0.0%
2028	0.1%	0.1%	0.0%
2029	0.2%	0.2%	0.0%

4 Medium-Duty and Heavy-Duty Electric Vehicle Forecasts

Vehicles classified as Medium-Duty Vehicles ("MDVs") weigh between 4,535 and 11,793 kilograms according to Statistics Canada. Vehicles classified as Heavy-Duty Vehicles ("HDVs") weigh more than 11,793 kilograms. Medium-Duty Electric Vehicles ("MDEVs") and Heavy-Duty Electric Vehicles ("HDEVs") are forecasted separately by Toronto Hydro.

The MDEV and HDEV count forecast was provided to Clearspring by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs.

The table below provides the historic and forecasted MDEVs and HDEVs in Toronto.

Table 10: Forecast for the Number of MDEVs and HDEVs in Toronto

Year	Total MDEVs in Toronto	Total HDEVs in Toronto
2022	0	0
2023	82	147
2024	210	479
2025	413	964
2026	674	1,560
2027	1,007	2,284
2028	1,502	3,095
2029	2,120	3,908

The MDEVs and HDEVs count forecasts for Toronto Hydro are allocated to the rate classes. The Integration Model uses the Manufacturing and Warehouse kWh usage percentages by rate class provided by Toronto Hydro to allocate the MDEVs by rate class. For the HDEV rate class allocations, the model uses the same Manufacturing and Warehouse kWh usage percentages plus the Toronto Transit Commission ("TTC") garage kWh usage. The TTC garage usage, which was provided by Toronto Hydro, and was added to the HDEV allocations because of TTC's Green Bus Program, is forecasted to purchase and add several electric buses to its fleet, which would be classified as HDEVs.

For display purposes, the following table displays the annual MDEV counts for each rate class. The model is, however, monthly with the MDEV and HDEV counts escalating to the annual numbers in December of each year.

Table 11: Forecasted Number of MDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	6	28	25	22
2024	0	0	16	73	64	56
2025	0	0	32	144	127	111
2026	0	0	51	235	207	181
2027	0	0	77	351	309	270
2028	0	0	115	523	461	403
2029	0	0	162	739	651	569

The following table displays the annual HDEV counts for each rate class.

Table 12: Forecasted Number of HDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	11	51	45	40
2024	0	0	36	166	145	132
2025	0	0	72	334	293	266
2026	0	0	116	540	474	430
2027	0	0	170	791	693	630
2028	0	0	230	1,072	940	854
2029	0	0	290	1,353	1,186	1,078

4.1 MDEV & HDEV Energy Forecast

Estimating the energy contribution of each MDEV and HDEV by month for each rate class involves multiplying the expected energy required to charge each vehicle in each month by the forecasted number of MDEV and HDEVs in each rate class. The Integration Model assumes that MDEVs require 103.56 kWh per day and HDEVs require 319.87 kWh of electricity per day. Both of these assumptions were provided from Toronto Hydro.

The following table displays the forecasted annual MDEV energy contribution for each rate class.

Table 13: Annual MDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	92,292	421,300	371,586	324,412
2024	0	0	315,744	1,441,332	1,271,252	1,109,863
2025	0	0	669,510	3,056,232	2,695,591	2,353,377
2026	0	0	1,159,758	5,294,152	4,669,433	4,076,634
2027	0	0	1,787,311	8,158,854	7,196,095	6,282,528
2028	0	0	2,667,883	12,178,551	10,741,461	9,377,799
2029	0	0	3,843,691	17,545,972	15,475,517	13,510,852

The following table displays the forecasted annual HDEV energy contribution for each rate class.

Table 14: Annual HDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	498,747	2,326,961	2,039,258	1,853,621
2024	0	0	2,052,675	9,576,983	8,392,895	7,628,877
2025	0	0	4,661,915	21,750,688	19,061,454	17,326,262
2026	0	0	8,091,377	37,751,224	33,083,701	30,072,043
2027	0	0	12,274,950	57,270,151	50,189,328	45,620,519
2028	0	0	17,126,372	79,905,004	70,025,630	63,651,094
2029	0	0	22,234,906	103,739,441	90,913,202	82,637,239

The energy forecasts are translated into monthly forecasts using the monthly MDEV and HDEV counts found in Table 11 and multiplying the average daily kWh charging by the number of days in each month. Similar to LDEVs, an additional monthly adjustment is made to account for the reality that EV batteries perform worse in cold temperatures. To adjust for this, the Integration Model adds ten percent to the energy totals in winter months and subtracted ten percent to the energy totals in summer months.

To integrate the MDEV/HDEV forecasted energy into the revenue forecast, the incremental load of MDEV and HDEVs for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental load in each month in 2025 to 2029 is the difference between that month's forecasted MDEV/HDEV load and the same month in 2023. The incremental load is used since the base revenue forecast uses a dataset through 2023 and, therefore, already has the 2023 MDEV/HDEV load embedded into the forecast.

Tables 16 and 17 below display the annual MDEV and HDEV incremental energy impacts from 2023 levels for each rate class. The model is, however, monthly.

Table 15: Annual MDEV Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	577,219	2,634,931	2,324,005	2,028,965
2026	0	0	1,067,467	4,872,852	4,297,847	3,752,222
2027	0	0	1,695,020	7,737,553	6,824,509	5,958,116
2028	0	0	2,575,591	11,757,251	10,369,875	9,053,387
2029	0	0	3,751,400	17,124,672	15,103,931	13,186,440

Table 16: Annual HDEV Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	4,163,168	19,423,726	17,022,196	15,472,641
2026	0	0	7,592,630	35,424,263	31,044,442	28,218,421
2027	0	0	11,776,202	54,943,190	48,150,070	43,766,898
2028	0	0	16,627,625	77,578,043	67,986,372	61,797,472
2029	0	0	21,736,159	101,412,480	88,873,944	80,783,617

Shown in Tables 18 and 19 are the average percentage increase in MDEV and HDEV energy from the base revenue forecast for each rate class.

Table 17: Annual Percentage MDEV Impact from Revenue Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
2026	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%
2027	0.0%	0.0%	0.1%	0.1%	0.2%	0.3%
2028	0.0%	0.0%	0.1%	0.1%	0.3%	0.5%
2029	0.0%	0.0%	0.2%	0.2%	0.4%	0.7%

Table 18: Annual Percentage HDEV Impact from Revenue Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.2%	0.2%	0.4%	1.0%
2026	0.0%	0.0%	0.3%	0.4%	0.8%	1.8%
2027	0.0%	0.0%	0.5%	0.6%	1.2%	2.9%
2028	0.0%	0.0%	0.7%	0.8%	1.7%	4.2%
2029	0.0%	0.0%	0.9%	1.1%	2.3%	5.8%

4.2 MDEV & HDEV Billing Demand Forecast

MDEVs and HDEVs will put upward pressure on Toronto Hydro's three rate classes with billing demand, and that pressure is a function of the number of EVs being charged at the premise, the load profiles of those EVs, and the base load profile for that customer. The model accounts for these factors by using hourly load profiles of the MDEV and HDEVs, analyzing smart meter interval data for customers from Toronto Hydro, and then examining how the estimated number of MDEV and HDEVs would impact billing demand for each general service customer.

The following table displays the hourly load profile used for MDEVs and HDEVs for both the summer and winter. This load profile is layered onto the customer-specific hourly interval data to calculate the difference in the before and after technology billing demands.

Table 19: Summer and Winter MDEV and HDEV Charging Load Profiles

Hour Beginning	Summer MDEV	Winter MDEV	Summer HDEV	Winter HDEV
0	4.023	4.917	28.98	35.42
1	4.113	5.027	25.236	30.844
2	3.663	4.477	19.35	23.65
3	4.356	5.324	14.76	18.04
4	4.104	5.016	14.166	17.314
5	3.6	4.4	12.141	14.839
6	3.177	3.883	12.798	15.642
7	2.862	3.498	11.907	14.553
8	0.855	1.045	2.421	2.959
9	1.008	1.232	8.694	10.626
10	1.8	2.2	10.467	12.793
11	2.052	2.508	13.653	16.687
12	4.086	4.994	11.673	14.267
13	3.663	4.477	10.332	12.628
14	3.564	4.356	10.944	13.376
15	4.761	5.819	9.459	11.561
16	5.697	6.963	9.171	11.209
17	5.166	6.314	8.784	10.736
18	4.932	6.028	6.417	7.843
19	5.013	6.127	5.823	7.117
20	5.778	7.062	4.419	5.401
21	5.805	7.095	4.032	4.928
22	5.13	6.27	3.285	4.015
23	4.023	4.917	28.98	35.42

For display purposes, the following table displays the annual MDEV incremental billing demand impact from 2023 levels for each rate class.

Table 20: MDEV Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2023	-	-	-
2024	1,996	1,584	1,408
2025	5,156	4,091	3,637
2026	9,538	7,567	6,721
2027	15,147	12,015	10,668
2028	23,014	18,257	16,213
2029	33,525	26,592	23,607

For display purposes, the following table displays the annual HDEV incremental billing demand impact from 2023 levels for each rate class.

Table 21: HDEV Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2023	-	-	-
2024	14,434	12,280	13,100
2025	38,730	32,947	35,149
2026	70,696	60,137	64,160
2027	109,695	93,310	99,554
2028	154,940	131,796	140,617
2029	202,618	172,350	183,889

Shown in the following table is the average percentage increase in MDEV billing demand from the base revenue forecast for each rate class.

Table 22: MDEV Percentage Demand Impact from Revenue Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.1%
2026	0.0%	0.1%	0.2%
2027	0.1%	0.2%	0.3%
2028	0.1%	0.2%	0.5%
2029	0.2%	0.3%	0.7%

Shown in the following table is the average percentage increase in HDEV billing demand from the base revenue forecast for each rate class.

Table 23: HDEV Percentage Demand Impact from Revenue Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.2%	0.4%	0.9%
2026	0.3%	0.7%	1.7%
2027	0.5%	1.2%	2.7%
2028	0.7%	1.7%	4.0%
2029	1.0%	2.2%	5.5%

5 Renewable DER Forecast

Toronto Hydro provided the Renewable nameplate capacity forecast, and historical, data to Clearspring. It is Clearspring's understanding that the Renewable forecast is entirely driven by solar. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting solar resources.[20]

The table below provides the 2022 to 2029 forecast for the Renewable capacity for Toronto Hydro.

Table 24: Annual Renewable Capacity Forecast by Year

Year	Total Renewable Nameplate kW
2022	100,366
2023	110,610
2024	117,616
2025	127,593
2026	139,278
2027	152,669
2028	167,768
2029	184,574

The Renewable capacity forecasted for Toronto Hydro is allocated to the different rate classes. The Integration Model uses the 2022 participation percentages in Toronto Hydro's net metering program by rate class to estimate the rate class allocations.

The following table displays the annual Renewable Capacity for each rate class.

Table 25: Forecasted Renewable Capacity by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	14,262	0	11,141	66,302	8,662	0
2023	15,718	0	12,278	73,069	9,546	0
2024	16,713	0	13,055	77,697	10,150	0
2025	18,131	0	14,163	84,288	11,011	0
2026	19,791	0	15,460	92,007	12,020	0
2027	21,694	0	16,946	100,853	13,175	0
2028	23,840	0	18,622	110,828	14,478	0
2029	26,228	0	20,488	121,930	15,929	0

5.1 Renewable Energy Forecast

Renewables are not able to produce the same amount of electricity continuously and consistently during every hour of the day. For instance, solar will produce substantially more electricity during summer

[20] https://www.iea.org/reports/renewables-2022/renewable-electricity#abstract

months and during the mid-day while sunlight is most direct. Toronto Hydro provided the hourly capacity factors to Clearspring for both summer and winter months. The table below provides the hourly capacity factors of a one kW nameplate capacity solar array for both summer and winter.

Table 26: Summer and Winter Renewable Production Hourly Profiles

Hour Beginning	Summer	Winter
0	0	0
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	0	0
7	-0.03	-0.01
8	-0.13	-0.02
9	-0.22	-0.04
10	-0.28	-0.05
11	-0.32	-0.06
12	-0.33	-0.06
13	-0.35	-0.07
14	-0.34	-0.06
15	-0.33	-0.06
16	-0.32	-0.06
17	-0.28	-0.05
18	-0.20	-0.04
19	-0.09	-0.02
20	0	0
21	0	0
22	0	0
23	0	0

The hourly capacity factors can be summed to estimate the average production per day of a one kW solar array.[21] In the summer, the sum of the production factors is -3.22, meaning that for every one kW nameplate capacity, a solar array will have an average production of 3.22 kWh's during the summer months. In the winter, the sum of the production factors is -0.60, meaning a 0.6 kWh production expectation during winter months. The Integration Model multiplies the average daily production by the number of days in each month to estimate the energy contribution of Renewables based on the estimated nameplate capacity in each rate class.

[21] These production factors are for "average" summer and winter days. Cloudy days will have lower production and clear days will have higher production.

The table below provides the annual Renewable energy contribution by rate class and year. The annual totals are provided below for display purposes; however, the model disaggregates the forecasts into monthly contributions to match and integrate with the base revenue forecast.

Table 27: Annual Renewable Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2022	-8,761,942	0	-6,844,303	-40,732,855	-5,321,292	0
2023	-9,353,911	0	-7,306,714	-43,484,823	-5,680,806	0
2024	-10,093,938	0	-7,884,779	-46,925,089	-6,130,238	0
2025	-10,859,950	0	-8,483,142	-50,486,158	-6,595,452	0
2026	-11,824,330	0	-9,236,457	-54,969,403	-7,181,138	0
2027	-12,939,083	0	-10,107,236	-60,151,711	-7,858,148	0
2028	-14,204,210	0	-11,095,477	-66,033,082	-8,626,484	0
2029	-15,619,711	0	-12,201,181	-72,613,517	-9,486,144	0

To integrate the Renewable forecasted energy into the revenue forecast, the incremental production of Renewables for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental production forecasted in each month in 2025 to 2029 is the difference between that month's forecasted production and the same month in 2023. The incremental production is used since the base revenue forecast uses a dataset through 2023 and, therefore, already has the 2023 Renewable production embedded into the forecast.

Table 28: Annual Incremental Renewable Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	-1,818,949	0	-1,420,854	-8,456,000	-1,104,682	0
2026	-2,783,328	0	-2,174,169	-12,939,244	-1,690,368	0
2027	-3,898,081	0	-3,044,947	-18,121,552	-2,367,378	0
2028	-5,163,208	0	-4,033,189	-24,002,924	-3,135,713	0
2029	-6,578,709	0	-5,138,893	-30,583,358	-3,995,374	0

Shown below is the average percentage impact from Renewables from the base revenue forecast for each rate class.

Table 29: Renewable Energy Percentage of Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	-0.1%	-0.1%	0.0%	0.0%
2026	-0.1%	0.0%	-0.1%	-0.1%	0.0%	0.0%
2027	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	0.0%
2028	-0.1%	0.0%	-0.2%	-0.3%	-0.1%	0.0%
2029	-0.1%	0.0%	-0.2%	-0.3%	-0.1%	0.0%

5.2 Renewable Billing Demand Forecast

Renewables will put downward pressure on Toronto Hydro's three rate classes regarding billing demand, and that pressure is a function of the nameplate capacity producing at the premise, the production profiles of those Renewables (provided in the table in the prior subsection), and the base load profile for that customer. The Integration Model accounts for these factors by using the hourly Renewable capacity factors, analyzing smart meter interval data for customers from Toronto Hydro, and then examining how the estimated production of the Renewables would impact billing demand for each general service customer.

The following table provides the forecasted incremental billing demand reductions by rate class of Renewables.[22]

Table 30: Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	(12,821)	(2,816)	-
2026	(19,614)	(4,309)	-
2027	(27,465)	(6,034)	-
2028	(36,375)	(7,991)	-
2029	(46,344)	(10,182)	-

Shown below is the average percentage impact from Renewables from the base revenue forecast for each rate class.

Table 31: Renewable Billing Demand Percentage of Base Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-0.1%	0.0%	0.0%
2026	-0.1%	0.0%	0.0%
2027	-0.1%	-0.1%	0.0%
2028	-0.2%	-0.1%	0.0%
2029	-0.2%	-0.1%	0.0%

[22] The forecast is monthly but annual numbers are provided for display purposes.

6 Non-Renewable DER Forecast

Toronto Hydro provided the behind-the-meter Non-Renewable nameplate capacity forecast and historical data to Clearspring. It is Clearspring's understanding that these Non-Renewable DERs will be actively dispatched by the IESO. The forecasts increase substantially until 2024 and then grow by less than two percent thereafter.

The table below provides the 2022 to 2029 forecast for Non-Renewable capacity for Toronto Hydro.

Table 32: Annual Non-Renewable Capacity Forecast by Year

Year	Total Nameplate kW
2022	170,013
2023	198,186
2024	212,056
2025	215,566
2026	218,717
2027	221,597
2028	224,297
2029	226,817

The Non-Renewable capacity forecasted for Toronto Hydro is then allocated to the different rate classes. The Integration Model uses the current nameplate capacity of non-renewable generation by rate class to estimate the rate class allocations.

For display purposes, the following table displays the annual Non-Renewable capacity for each rate class.

Table 33: Forecasted Non-Renewable Capacity by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	95	32,026	70,748	67,145
2023	0	0	110	37,333	82,471	78,271
2024	0	0	118	39,946	88,243	83,749
2025	0	0	120	40,607	89,704	85,135
2026	0	0	122	41,201	91,015	86,379
2027	0	0	123	41,743	92,214	87,517
2028	0	0	125	42,252	93,337	88,583
2029	0	0	126	42,726	94,386	89,579

6.1 Non-Renewable DER Energy Forecast

Unlike Renewables, Non-Renewables can continuously and consistently produce the same amount of electricity in any hour of the day and are not significantly impacted by winter/summer conditions. Toronto Hydro provided the capacity factors by hour for the existing Non-Renewable generation on its system that are dispatched by the IESO. These capacity factors are for an average day and are the same for both winter and summer months.

The table below provides the hourly production factors of a one kW Non-Renewable nameplate capacity.

Table 34: Non-Renewable Production Hourly Profile

Hour Beginning	Non-Renewable
0	-0.66
1	-0.65
2	-0.65
3	-0.65
4	-0.65
5	-0.65
6	-0.66
7	-0.67
8	-0.67
9	-0.67
10	-0.67
11	-0.67
12	-0.67
13	-0.67
14	-0.68
15	-0.68
16	-0.68
17	-0.67
18	-0.67
19	-0.67
20	-0.67
21	-0.66
22	-0.66
23	-0.66

The hourly capacity factors can be summed to estimate the average production per day of a one kW Non-Renewable resource. The sum of the production factors is -15.96. This means that on an average day, for every one kW of Non-Renewable nameplate capacity, 15.96 kWh's will be generated. The Integration Model multiplies this sum by the number of days in each month to estimate the energy contribution of Non-Renewables based on the estimated nameplate capacity in each rate class. The table below provides the annual Non-Renewable energy contribution by rate class and year.

The annual Non-Renewable energy contributions by rate class are provided below for display purposes; however, the model disaggregates the forecasts into monthly contributions to match and integrate with the base revenue forecast.

Table 35: Annual Non-Renewable Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2022	0	0	-550,179	-186,298,506	-411,547,347	-390,586,651
2023	0	0	-600,616	-203,377,196	-449,275,454	-426,393,211
2024	0	0	-666,709	-225,757,248	-498,714,663	-473,314,410
2025	0	0	-693,400	-234,795,282	-518,680,357	-492,263,223
2026	0	0	-704,142	-238,432,497	-526,715,237	-499,888,875
2027	0	0	-713,875	-241,728,342	-533,996,005	-506,798,824
2028	0	0	-722,892	-244,781,589	-540,740,858	-513,200,151
2029	0	0	-731,325	-247,637,294	-547,049,324	-519,187,318

To integrate the Non-Renewable forecasted energy into the revenue forecast, the incremental production of Non-Renewables for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental production forecasted in each month in 2025 to 2029 is the difference between that month's forecasted production and the same month in 2023.

Table 36: Annual Incremental Non-Renewable Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	-92,784	-31,418,086	-69,404,903	-65,870,012
2026	0	0	-103,526	-35,055,300	-77,439,783	-73,495,664
2027	0	0	-113,259	-38,351,145	-84,720,552	-80,405,613
2028	0	0	-122,276	-41,404,393	-91,465,404	-86,806,940
2029	0	0	-130,709	-44,260,098	-97,773,870	-92,794,107

Shown below is the average percentage impact from Non-Renewables from the base revenue forecast for each rate class.

Table 37: Non-Renewable Energy Percentage of Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%	-0.3%	-1.7%	-4.1%
2026	0.0%	0.0%	0.0%	-0.4%	-1.9%	-4.6%
2027	0.0%	0.0%	0.0%	-0.4%	-2.1%	-5.2%
2028	0.0%	0.0%	0.0%	-0.4%	-2.3%	-5.8%
2029	0.0%	0.0%	0.0%	-0.5%	-2.5%	-6.6%

6.2 Non-Renewable DER Demand Forecast

Non-Renewables will put downward pressure on billing demand and is a function of the nameplate capacity producing at the premise, the production profiles of those Non-Renewables (provided in the table in the prior subsection), and the base load profile for every customer. The Integration Model accounts for these factors by using the hourly Non-Renewable capacity factors provided by Toronto Hydro, receiving smart meter interval data for customers from Toronto Hydro, and then analyzing how the estimated production of the Non-Renewables would impact billing demand for each general service customer.

The following table provides the forecasted incremental billing demand reductions by rate class of Non-Renewables.[23]

Table 38: Incremental Non-Renewable Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-43,383	-95,783	-90,780
2026	-48,397	-106,855	-101,272
2027	-52,941	-116,887	-110,778
2028	-57,150	-126,180	-119,585
2029	-61,087	-134,871	-127,822

Shown below is the average percentage impact from Non-Renewables from the base revenue forecast for each rate class.

Table 39: Non-Renewable Billing Demand Percentage of Base Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-0.2%	-1.1%	-2.3%
2026	-0.2%	-1.3%	-2.5%
2027	-0.2%	-1.4%	-2.9%
2028	-0.3%	-1.5%	-3.2%
2029	-0.3%	-1.7%	-3.6%

[23] The forecast is monthly but we show annual numbers for display purposes.

7 Energy Storage Forecast

Energy storage can be used for multiple purposes. One viable option may be for back-up power when outages are encountered. Another possible purpose is to reduce billing peaks or shift energy use from on-peak to off-peak. If energy storage is actively used to reduce billing demands, this could have the impact of reducing demands but increasing energy use at the premise through energy losses that result from the inefficiency in the discharge/charging cycle. Under the back-up option, there would be minimal impacts on demand and energy.

It is unclear how energy storage will be used in the future on Toronto Hydro's system. There is no evidence yet that reveals how energy storage may be used on the system and if its presence will result in meaningful energy or billing demand changes. Given this current lack of evidence, it is assumed that energy storage will only be used for back-up power through the forecast period meaning that energy storage is assumed to have zero kWh and zero kW impacts.

The forecasted energy storage nameplate kW, provided by Toronto Hydro, are presented in Table 40 below.

Table 40: Annual Energy Storage Nameplate kW

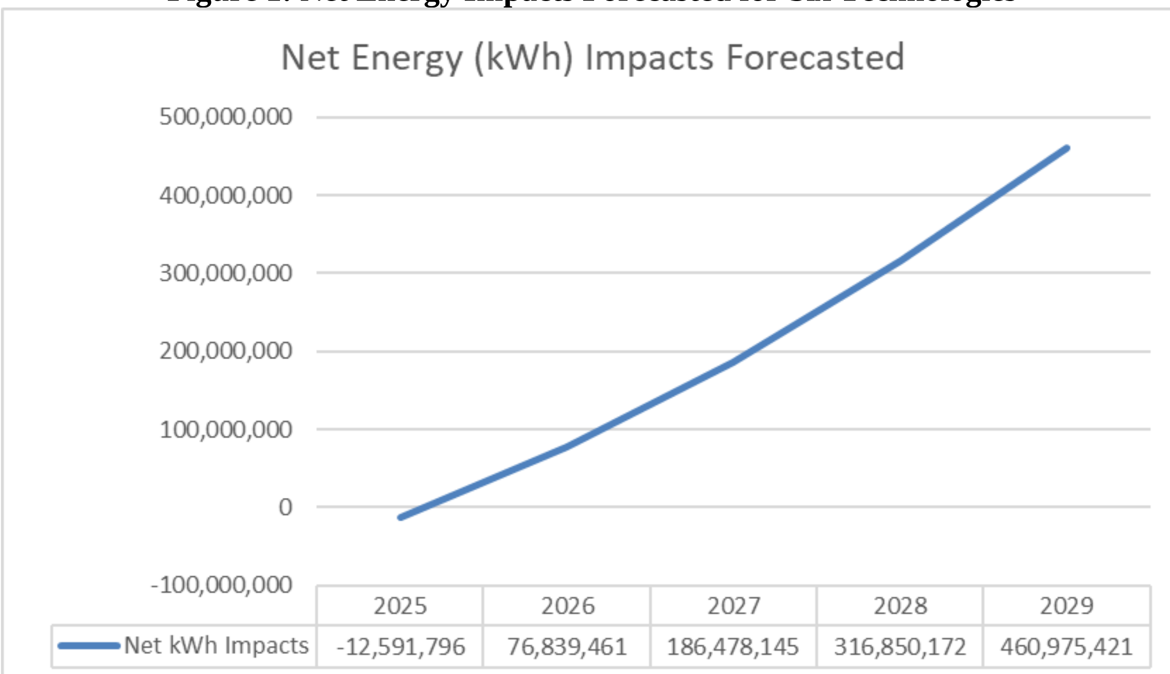
Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2019	12	0	0	803	3,338	4,926
2020	24	0	0	1,553	6,457	9,531
2021	25	0	0	1,609	6,692	9,876
2022	25	0	0	1,656	6,883	10,159
2023	77	0	0	5,003	20,800	30,699
2024	82	0	0	5,309	22,073	32,578
2025	100	0	0	6,487	26,969	39,804
2026	105	0	0	6,842	28,446	41,984
2027	111	0	0	7,198	29,927	44,171
2028	116	0	0	7,554	31,408	46,357
2029	122	0	0	7,912	32,897	48,553

8 Net Results

The six technology inputs can be aggregated and layered onto the base revenue forecast to determine the expected forecast after accounting for the incremental impacts of the technologies. There is a balancing of impacts between the technologies, as EVs will increase energy and billing demand, while DERs will lower energy and billing demand.

The net forecasted energy impacts are provided below annually.[24]

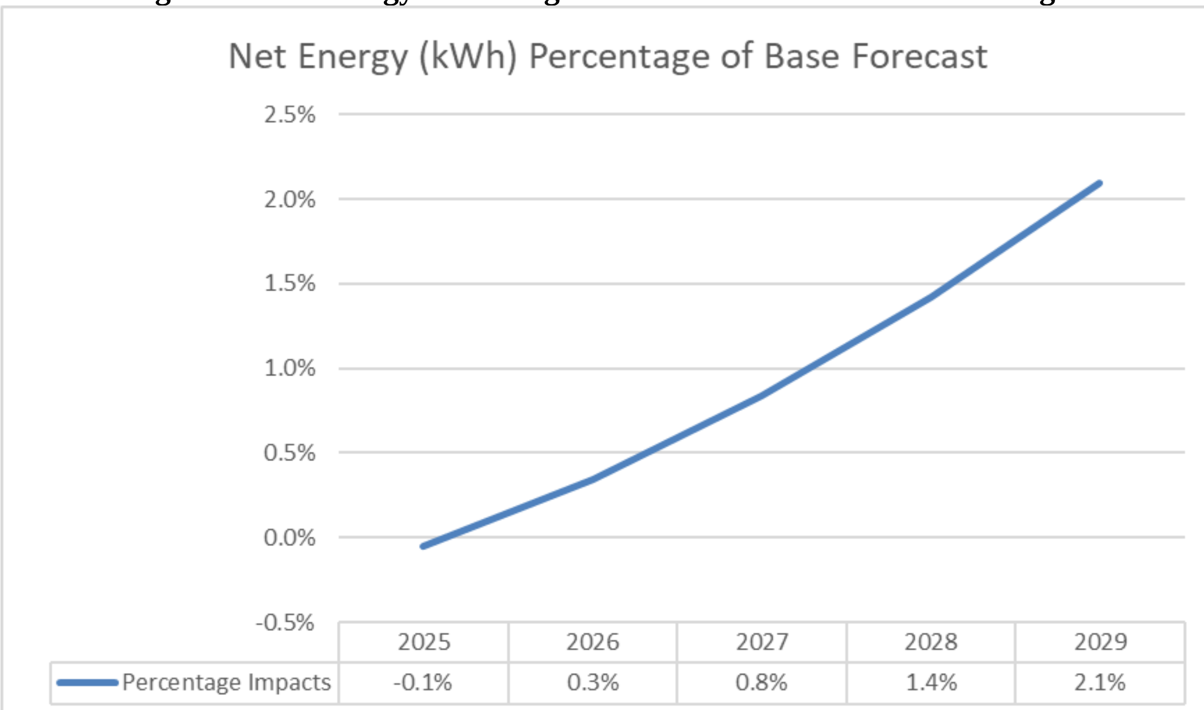
Figure 1: Net Energy Impacts Forecasted for Six Technologies



[24] The forecasts are integrated on a monthly basis as the base revenue forecast is monthly, but we display annual impacts here for display purposes.

The following graph displays the percentage difference of the net energy impacts, in kWh's, relative to the total energy for that same year in the base revenue forecast.

Figure 2: Net Energy Percentage of Base Forecast for Six Technologies



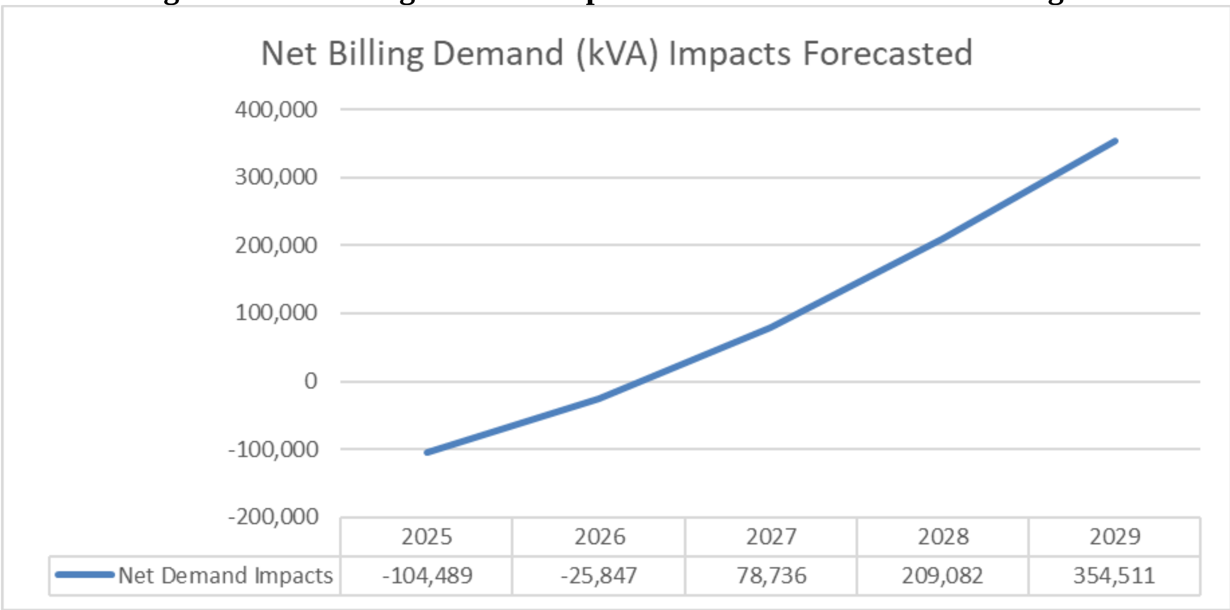
The following table displays, annually, the forecasted net energy by rate class that is projected to be added in 2025 to 2029.

Table 41: Annual Incremental Net Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	92,227,387	593,699	5,205,746	-13,065,835	-49,382,286	-48,170,506
2026	148,504,808	955,057	9,565,925	-56,972	-40,922,689	-41,206,668
2027	211,452,614	1,359,474	14,844,594	17,083,835	-28,034,931	-30,227,441
2028	281,703,920	1,810,945	21,084,234	38,415,539	-10,812,035	-15,352,432
2029	357,655,979	2,299,354	27,882,469	62,088,527	9,106,692	1,942,401

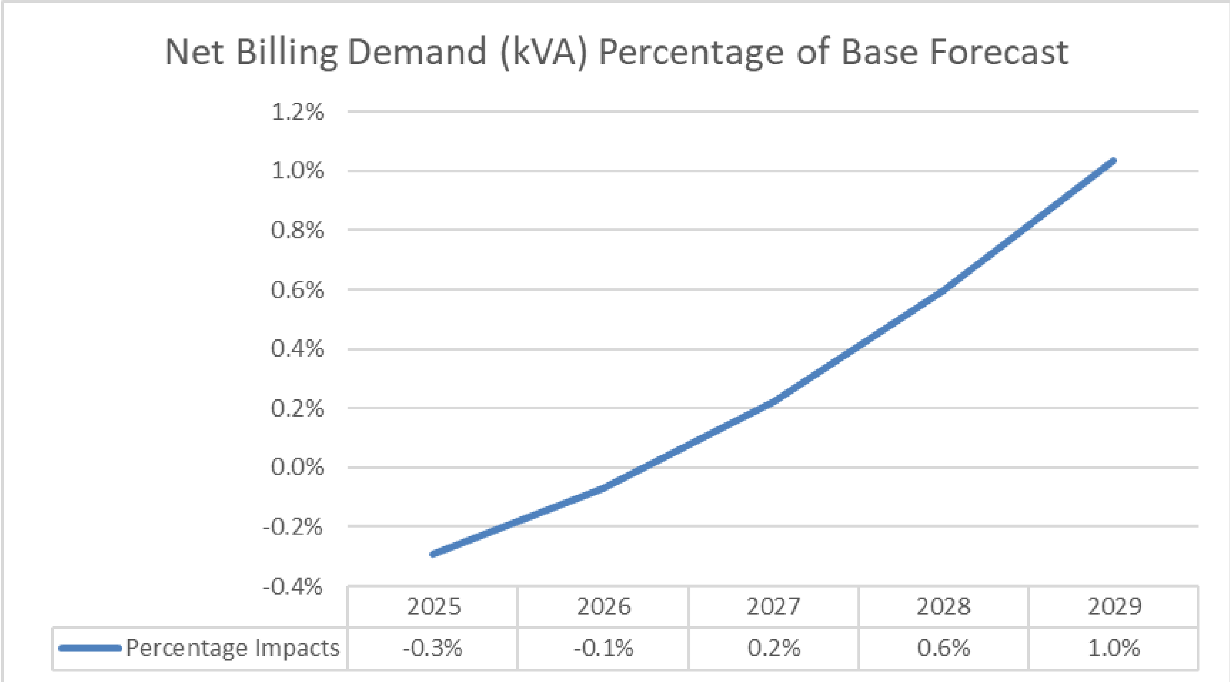
The net forecasted billing demand impacts are provided below annually.

Figure 3: Net Billing Demand Impacts Forecasted for Six Technologies



The following graph displays the percentage difference of the net demand impacts, in kVA, relative to the total billing demand in the base revenue forecast.

Figure 4: Net Billing Demand Percentage of Base Forecast for Six Technologies



The following table displays, annually, the forecasted net billing demand by rate class that is projected to be added in 2025 to 2029.

Table 42: Annual Incremental Net Billing Demand by Rate Class (kVA)

Year	GS50-999 kW	GS 1-5 MW	LU
2025	587	-55,536	-49,540
2026	33,489	-33,339	-25,997
2027	75,266	-2,718	6,188
2028	126,111	36,214	46,757
2029	182,172	80,147	92,192

9 Load Profiles

To assist with the cost allocation model ("CAM") study used for rate setting purposes by Toronto Hydro, Clearspring performed a detailed comparison between hourly 2019 rate class load profiles and hourly 2019 load profiles modified with 2025 EV and DER forecasted load impacts (LDEVs, MDEVs, HDEVs, Renewable, and non-renewable DERs). This analysis provides Toronto Hydro with the changes in the rate class allocators used within the CAM due to the anticipated changes in the technologies studied in the Integration Model.

The 2025 hourly EV/DER loads were constructed by multiplying the expected LDEV, MDEV, and HDEV counts by the same kW load profiles used in the Integration Model. Similarly, for Renewable and Non-Renewable DERs, the 2025 loads were forecasted by multiplying the total nameplate capacities by the kW load profiles used in the Integration Model.

One load profile needed to be added to the analysis: a residential LDEV load profile. For the Integration Model, it was not necessary to include a residential LDEV load profile because billing demand is not a component of residential rates. However, how LDEV's may impact the cost allocations between the residential and other classes in the CAM is pertinent.

The residential LDEV load profile assumed that EV owners would typically "smart charge" their vehicles in response to time-of-use pricing such as the Ultra-Low Overnight ("ULO") rate offering. The ULO provides a steep reduction in the electricity rate if consumers use electricity during off-peak, night-time hours. Our analysis assumes that consumers are typically charging vehicles during this time by using an LDEV load profile derived from the Alternative Fuels Data Center of the U.S. Department of Energy ("DOE") that estimates the load shape of residential LDEVs in the presence of smart charging.[25] This DOE load shape was then scaled to match the energy assumptions for the City of Toronto used in the Integration Model. The seasonal adjustment of adding ten percent for winter months and subtracting ten percent for summer months consistent with the Integration Model is also implemented for the CAM analysis.

[25] https://afdc.energy.gov/evi-pro-lite/load-profile/. The load shape used Chicago as the target city, 25 miles of travel per day in a shoulder month, and Level 1 charging.

The following table displays the residential LDEV load profiles used for the analysis.

Table 43: Residential, Smart Charging LDEV Load Profile for Toronto Hydro

Hour Beginning	Summer LDEV	Winter LDEV
0	1.319	1.612
1	1.023	1.250
2	0.782	0.956
3	0.587	0.717
4	0.390	0.476
5	0.251	0.306
6	0.141	0.173
7	0.086	0.105
8	0.057	0.070
9	0.043	0.052
10	0.041	0.050
11	0.047	0.057
12	0.052	0.064
13	0.059	0.072
14	0.085	0.104
15	0.124	0.151
16	0.170	0.208
17	0.217	0.265
18	0.245	0.299
19	0.271	0.332
20	0.295	0.360
21	0.307	0.375
22	0.305	0.373
23	1.556	1.902

The CAM input tables are compiled by calculating the yearly, quarterly, and monthly noncoincident ("NCP") and coincident peaks ("CP") and comparing the percent differences between the peaks that did not include the impacts of the six technologies and the peaks that did have the 2025 loads added.[26] Ultimately, adding the EV and DER loads to 2019 load data increases the NCP and CPs for the residential, CSMur, and GS<50 rate classes, while it decreases the NCP and CPs for the GS50-999, GS1-5MW, and LU rate classes. The increases are due to EVs having a larger impact on peaks for the lower-use rate classes, whereas the forecasted increase in DERs by 2025 causes peaks to drop for the larger use rate classes.

[26] The NCP or CP impacts of the CAManalysis will not match the demand impacts found in the Integration Model because of the different definitions of demand being analyzed. In the Integration Model, it is billing demand that is relevant which is based on each individual customer's own peak during the month. For the CAM analysis, the relevant peak demand is either the rate class non-coincident peak or the system coincident peak.

The following table displays the annual, quarterly, and monthly NCPs for the 2019 data prior to adding 2025 technology impacts and then the NCPs after adding in the impacts.[27]

Table 44: NCPs Before and After 2025 Technology Impacts by Rate Class

	RES	CSMUR	GS<50	GS50-999	GS1-5MW	LU	SL	USL	**Total**
1NCP: 2025Baseline	1,202,242	81,697	642,970	1,577,135	645,935	310,050	31,389	6,323	**4,497,741**
1NCP: 2025Net	1,212,328	81,797	642,961	1,566,120	625,420	290,411	31,389	6,323	**4,456,749**
% Increase	0.8%	0.1%	0.0%	-0.7%	-3.2%	-6.3%	0.0%	0.0%	-0.9%
4NCP: 2025Baseline	4,364,424	300,589	2,502,247	6,194,492	2,516,961	1,195,740	121,365	24,249	**17,220,066**
4NCP: 2025Net	4,410,788	300,966	2,502,763	6,152,751	2,432,341	1,115,494	121,365	24,249	**17,060,716**
% Increase	1.1%	0.1%	0.0%	-0.7%	-3.4%	-6.7%	0.0%	0.0%	-0.9%
12NCP: 2025Baseline	10,817,700	831,752	6,753,047	17,271,260	6,912,953	3,347,378	348,075	70,127	**46,352,293**
12NCP: 2025Net	10,981,253	832,870	6,763,953	17,168,462	6,666,153	3,115,743	348,075	70,127	**45,946,635**
% Increase	1.5%	0.1%	0.2%	-0.6%	-3.6%	-6.9%	0.0%	0.0%	-0.9%

The following table displays the annual, quarterly, and monthly CPs for the 2019 data prior to adding 2025 technology impacts and then the CPs after adding in the impacts.

Table 45: CPs Before and After 2025 Technology Impacts by Rate Class

	RES	CSMUR	GS<50	GS50-999	GS1-5MW	LU	SL	USL	**Total**
1CP: 2025Baseline	884,507	46,895	642,970	1,571,419	641,174	290,102	-	4,429	**4,081,498**
1CP: 2025Net	913,274	48,766	638,780	1,551,590	615,798	255,329	-	4,437	**4,027,973**
% Increase	3.3%	4.0%	-0.7%	-1.3%	-4.0%	-12.0%		0.2%	-1.3%
4CP: 2025Baseline	3,551,046	218,023	2,344,649	6,117,966	2,355,768	1,037,809	28,111	19,135	**15,672,506**
4CP: 2025Net	3,603,754	220,065	2,341,719	6,064,921	2,266,427	942,752	28,111	19,142	**15,486,890**
% Increase	1.5%	0.9%	-0.1%	-0.9%	-3.8%	-9.2%	0.0%	0.0%	-1.2%
12CP: 2025Baseline	8,757,869	644,093	6,321,104	16,957,736	6,682,659	3,037,182	140,169	59,368	**42,600,180**
12CP: 2025Net	8,891,672	646,676	6,324,315	16,834,621	6,425,229	2,781,677	140,169	59,376	**42,103,735**
% Increase	1.5%	0.4%	0.1%	-0.7%	-3.9%	-8.4%	0.0%	0.0%	-1.2%

[27] The following tables include metered and unmetered street lighting but there are zero impacts of the technologies assumed on those rate classes.

Appendix A: Monthly Projected Impacts by Technology by Rate Class from the Integration Model

The following tables provide the forecasted monthly impacts for each technology resulting from the Integration Model.

LDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	7,864,340	49,646	165,488	397,170	628	148,939	326	16,549	33
Feb-25	7,232,014	45,655	152,182	365,236	921	136,964	352	15,218	29
Mar-25	8,149,405	51,446	171,486	411,567	1,086	154,338	352	17,149	38
Apr-25	8,024,456	50,657	168,857	405,257	1,034	151,971	328	16,886	32
May-25	6,900,930	43,564	145,215	348,516	803	130,693	288	14,521	32
Jun-25	6,791,175	42,872	142,905	342,973	744	128,615	329	14,291	33
Jul-25	7,134,165	45,037	150,123	360,295	720	135,110	316	15,012	36
Aug-25	7,250,782	45,773	152,577	366,184	706	137,319	311	15,258	38
Sep-25	7,129,742	45,009	150,030	360,071	854	135,027	318	15,003	31
Oct-25	9,147,132	57,744	192,481	461,955	993	173,233	357	19,248	39
Nov-25	8,989,998	56,752	189,175	454,019	1,084	170,257	376	18,917	31
Dec-25	9,432,197	59,544	198,480	476,351	1,022	178,632	422	19,848	39
Jan-26	12,953,184	81,771	272,571	654,171	1,034	245,314	537	27,257	55
Feb-26	11,857,010	74,851	249,505	598,811	1,510	224,554	577	24,950	48
Mar-26	13,301,624	83,971	279,903	671,768	1,773	251,913	574	27,990	62
Apr-26	13,041,139	82,327	274,422	658,613	1,681	246,980	533	27,442	51
May-26	11,168,233	70,503	235,011	564,026	1,299	211,510	466	23,501	52
Jun-26	10,945,913	69,100	230,333	552,798	1,199	207,299	531	23,033	54
Jul-26	11,453,320	72,303	241,010	578,423	1,155	216,909	507	24,101	58
Aug-26	11,595,864	73,203	244,009	585,622	1,129	219,608	497	24,401	61
Sep-26	11,359,749	71,712	239,041	573,698	1,361	215,137	507	23,904	49
Oct-26	14,521,162	91,670	305,566	733,358	1,576	275,009	566	30,557	61
Nov-26	14,221,337	89,777	299,257	718,216	1,714	269,331	595	29,926	50
Dec-26	14,869,601	93,869	312,898	750,955	1,611	281,608	665	31,290	61
Jan-27	18,460,325	116,537	388,457	932,296	1,474	349,611	766	38,846	78
Feb-27	16,894,190	106,650	355,501	853,202	2,152	319,951	823	35,550	69
Mar-27	18,948,238	119,617	398,724	956,937	2,525	358,851	818	39,872	88
Apr-27	18,573,091	117,249	390,830	937,991	2,394	351,747	759	39,083	73
May-27	15,902,305	100,389	334,629	803,109	1,849	301,166	664	33,463	74
Jun-27	15,582,489	98,370	327,899	786,958	1,707	295,109	756	32,790	76
Jul-27	16,301,506	102,909	343,029	823,270	1,644	308,726	722	34,303	83
Aug-27	16,501,106	104,169	347,229	833,350	1,606	312,506	708	34,723	87
Sep-27	16,161,974	102,028	340,093	816,223	1,937	306,084	721	34,009	70
Oct-27	20,655,931	130,398	434,658	1,043,180	2,242	391,193	806	43,466	87
Nov-27	20,225,697	127,682	425,605	1,021,452	2,438	383,045	847	42,561	70
Dec-27	21,143,844	133,478	444,925	1,067,821	2,290	400,433	946	44,493	87
Jan-28	24,780,945	156,438	521,460	1,251,504	1,978	469,314	1028	52,146	105
Feb-28	22,645,026	142,954	476,514	1,143,635	2,884	428,863	1103	47,651	92
Mar-28	25,361,613	160,104	533,679	1,280,830	3,380	480,311	1095	53,368	118
Apr-28	24,824,465	156,713	522,376	1,253,702	3,200	470,138	1015	52,238	98
May-28	21,225,502	133,993	446,644	1,071,945	2,468	401,979	886	44,664	99
Jun-28	20,770,692	131,122	437,073	1,048,976	2,276	393,366	1007	43,707	102
Jul-28	21,700,594	136,992	456,641	1,095,938	2,189	410,977	961	45,664	110
Aug-28	21,938,140	138,492	461,640	1,107,935	2,135	415,476	941	46,164	116
Sep-28	21,460,341	135,476	451,585	1,083,805	2,572	406,427	957	45,159	93
Oct-28	27,393,950	172,934	576,445	1,383,468	2,974	518,801	1069	57,645	116
Nov-28	26,791,242	169,129	563,762	1,353,030	3,229	507,386	1122	56,376	93
Dec-28	27,974,618	176,599	588,664	1,412,793	3,030	529,798	1252	58,866	115
Jan-29	31,655,232	199,834	666,114	1,598,674	2,527	599,503	1313	66,611	134
Feb-29	28,893,361	182,399	607,997	1,459,192	3,680	547,197	1407	60,800	117
Mar-29	32,322,924	204,049	680,164	1,632,395	4,308	612,148	1396	68,016	151
Apr-29	31,603,326	199,507	665,022	1,596,053	4,073	598,520	1292	66,502	124
May-29	26,992,323	170,398	567,994	1,363,185	3,139	511,194	1127	56,799	126
Jun-29	26,385,939	166,570	555,234	1,332,561	2,891	499,710	1280	55,523	129
Jul-29	27,538,617	173,847	579,489	1,390,774	2,778	521,540	1219	57,949	140
Aug-29	27,811,764	175,571	585,237	1,404,569	2,707	526,713	1193	58,524	147
Sep-29	27,178,946	171,576	571,921	1,372,610	3,257	514,729	1212	57,192	118
Oct-29	34,659,849	218,802	729,340	1,750,416	3,763	656,406	1352	72,934	146
Nov-29	33,864,866	213,783	712,611	1,710,267	4,082	641,350	1418	71,261	118
Dec-29	35,327,541	223,017	743,390	1,784,136	3,827	669,051	1581	74,339	145

MDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	0	0	42,318	193,177	405	170,382	314	148,751	260
Feb-25	0	0	39,992	182,560	417	161,018	316	140,576	281
Mar-25	0	0	46,236	211,063	415	186,157	336	162,524	284
Apr-25	0	0	46,641	212,909	430	187,786	357	163,946	319
May-25	0	0	41,036	187,322	366	165,218	308	144,243	273
Jun-25	0	0	41,263	188,360	397	166,134	293	145,042	264
Jul-25	0	0	44,241	201,956	440	178,125	314	155,511	262
Aug-25	0	0	45,844	209,273	426	184,579	337	161,146	280
Sep-25	0	0	45,917	209,603	424	184,870	338	161,400	313
Oct-25	0	0	59,950	273,664	532	241,372	464	210,729	392
Nov-25	0	0	59,912	273,491	603	241,219	465	210,595	435
Dec-25	0	0	63,868	291,550	571	257,147	465	224,501	465
Jan-26	0	0	82,427	376,269	789	331,869	611	289,737	507
Feb-26	0	0	77,037	351,663	804	310,166	609	270,790	542
Mar-26	0	0	88,154	402,414	791	354,928	641	309,869	542
Apr-26	0	0	88,082	402,083	812	354,637	673	309,615	602
May-26	0	0	76,812	350,639	684	309,263	577	270,001	510
Jun-26	0	0	76,602	349,678	737	308,416	544	269,261	490
Jul-26	0	0	81,498	372,030	811	328,129	579	286,472	482
Aug-26	0	0	83,841	382,725	779	337,563	616	294,708	512
Sep-26	0	0	83,404	380,730	770	335,803	614	293,172	569
Oct-26	0	0	108,200	493,920	960	435,636	838	380,331	708
Nov-26	0	0	107,481	490,637	1,082	432,741	835	377,803	780
Dec-26	0	0	113,927	520,064	1,019	458,696	829	400,463	830
Jan-27	0	0	133,663	610,157	1,280	538,157	991	469,837	822
Feb-27	0	0	124,378	567,770	1,298	500,773	983	437,198	875
Mar-27	0	0	141,745	647,049	1,271	570,696	1,031	498,245	872
Apr-27	0	0	141,083	644,028	1,301	568,031	1,078	495,918	964
May-27	0	0	122,586	559,588	1,092	493,556	920	430,898	815
Jun-27	0	0	121,831	556,143	1,173	490,517	865	428,244	779
Jul-27	0	0	129,198	589,773	1,285	520,179	918	454,140	764
Aug-27	0	0	132,504	604,865	1,232	533,490	974	465,762	809
Sep-27	0	0	131,429	599,959	1,213	529,163	967	461,984	896
Oct-27	0	0	170,031	776,172	1,508	684,582	1,317	597,672	1,113
Nov-27	0	0	168,457	768,985	1,696	678,244	1,308	592,138	1,223
Dec-27	0	0	178,113	813,064	1,593	717,121	1,296	626,080	1,298
Jan-28	0	0	200,435	914,959	1,919	806,992	1,486	704,542	1,232
Feb-28	0	0	187,023	853,735	1,952	752,993	1,478	657,398	1,316
Mar-28	0	0	213,687	975,455	1,917	860,350	1,554	751,126	1,314
Apr-28	0	0	213,207	973,261	1,967	858,415	1,630	749,436	1,457
May-28	0	0	185,678	847,597	1,654	747,579	1,394	652,671	1,234
Jun-28	0	0	184,935	844,205	1,780	744,587	1,312	650,060	1,182
Jul-28	0	0	196,521	897,094	1,955	791,235	1,396	690,785	1,162
Aug-28	0	0	201,942	921,842	1,877	813,063	1,484	709,842	1,233
Sep-28	0	0	200,675	916,055	1,853	807,959	1,477	705,386	1,369
Oct-28	0	0	260,071	1,187,192	2,307	1,047,101	2,014	914,169	1,702
Nov-28	0	0	258,094	1,178,168	2,599	1,039,142	2,005	907,220	1,874
Dec-28	0	0	273,324	1,247,688	2,445	1,100,459	1,989	960,752	1,992
Jan-29	0	0	297,632	1,358,654	2,850	1,198,331	2,207	1,046,199	1,830
Feb-29	0	0	276,609	1,262,686	2,887	1,113,687	2,186	972,301	1,946
Mar-29	0	0	314,859	1,437,293	2,824	1,267,690	2,289	1,106,752	1,937
Apr-29	0	0	313,038	1,428,979	2,888	1,260,357	2,393	1,100,351	2,140
May-29	0	0	271,707	1,240,307	2,421	1,093,949	2,040	955,069	1,806
Jun-29	0	0	269,762	1,231,430	2,596	1,086,119	1,914	948,233	1,724
Jul-29	0	0	285,801	1,304,648	2,843	1,150,697	2,030	1,004,613	1,689
Aug-29	0	0	292,849	1,336,818	2,722	1,179,071	2,152	1,029,385	1,787
Sep-29	0	0	290,222	1,324,828	2,679	1,168,496	2,136	1,020,151	1,979
Oct-29	0	0	375,153	1,712,527	3,328	1,510,446	2,905	1,318,690	2,455
Nov-29	0	0	371,387	1,695,336	3,740	1,495,283	2,885	1,305,452	2,697
Dec-29	0	0	392,380	1,791,166	3,510	1,579,805	2,855	1,379,244	2,860

HDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	-	-	293,308	1,368,463	3,124	1,199,268	2,464	1,090,097	2,708
Feb-25	-	-	279,647	1,304,722	2,989	1,143,408	2,745	1,039,322	2,981
Mar-25	-	-	325,909	1,520,565	3,370	1,332,564	2,727	1,211,258	2,854
Apr-25	-	-	331,170	1,545,112	3,509	1,354,076	2,869	1,230,812	3,004
May-25	-	-	293,326	1,368,545	2,641	1,199,340	2,254	1,090,162	2,473
Jun-25	-	-	296,770	1,384,615	2,656	1,213,422	2,364	1,102,963	2,365
Jul-25	-	-	319,999	1,492,992	2,777	1,308,400	2,565	1,189,294	2,802
Aug-25	-	-	333,336	1,555,215	2,824	1,362,930	2,637	1,238,860	2,667
Sep-25	-	-	335,489	1,565,263	3,052	1,371,735	2,695	1,246,864	2,885
Oct-25	-	-	440,011	2,052,920	4,057	1,799,099	3,582	1,635,324	3,775
Nov-25	-	-	441,591	2,060,294	4,976	1,805,561	3,788	1,641,198	4,282
Dec-25	-	-	472,611	2,205,021	4,794	1,932,395	3,992	1,756,486	4,204
Jan-26	-	-	579,105	2,701,881	6,169	2,367,823	4,865	2,152,276	5,347
Feb-26	-	-	542,642	2,531,756	5,799	2,218,732	5,327	2,016,758	5,784
Mar-26	-	-	622,459	2,904,150	6,437	2,545,084	5,209	2,313,401	5,450
Apr-26	-	-	623,357	2,908,341	6,606	2,548,756	5,399	2,316,739	5,655
May-26	-	-	544,755	2,541,617	4,906	2,227,374	4,185	2,024,613	4,592
Jun-26	-	-	544,346	2,539,706	4,871	2,225,700	4,336	2,023,091	4,338
Jul-26	-	-	580,226	2,707,110	5,035	2,372,406	4,650	2,156,442	5,082
Aug-26	-	-	597,962	2,789,857	5,066	2,444,922	4,730	2,222,357	4,784
Sep-26	-	-	595,836	2,779,939	5,421	2,436,230	4,786	2,214,456	5,124
Oct-26	-	-	774,195	3,612,095	7,138	3,165,499	6,302	2,877,339	6,642
Nov-26	-	-	770,199	3,593,448	8,679	3,149,158	6,607	2,862,485	7,468
Dec-26	-	-	817,549	3,814,364	8,292	3,342,760	6,905	3,038,464	7,272
Jan-27	-	-	930,161	4,339,771	9,908	3,803,206	7,814	3,456,995	8,588
Feb-27	-	-	865,251	4,036,925	9,247	3,537,804	8,495	3,215,752	9,223
Mar-27	-	-	985,752	4,599,135	10,193	4,030,502	8,250	3,663,600	8,631
Apr-27	-	-	980,852	4,576,274	10,394	4,010,468	8,496	3,645,390	8,898
May-27	-	-	852,007	3,975,135	7,672	3,483,654	6,546	3,166,532	7,183
Jun-27	-	-	846,531	3,949,586	7,575	3,461,263	6,743	3,146,179	6,746
Jul-27	-	-	897,491	4,187,342	7,788	3,669,624	7,193	3,335,572	7,860
Aug-27	-	-	920,232	4,293,446	7,796	3,762,608	7,280	3,420,093	7,362
Sep-27	-	-	912,555	4,257,628	8,303	3,731,219	7,330	3,391,561	7,848
Oct-27	-	-	1,180,319	5,506,909	10,882	4,826,040	9,608	4,386,719	10,126
Nov-27	-	-	1,169,143	5,454,765	13,174	4,780,344	10,030	4,345,182	11,336
Dec-27	-	-	1,235,909	5,766,273	12,535	5,053,337	10,438	4,593,324	10,993
Jan-28	-	-	1,352,787	6,311,580	14,410	5,531,223	11,364	5,027,708	12,490
Feb-28	-	-	1,250,830	5,835,889	13,368	5,114,346	12,280	4,648,779	13,334
Mar-28	-	-	1,416,909	6,610,746	14,652	5,793,400	11,858	5,266,018	12,406
Apr-28	-	-	1,402,229	6,542,254	14,859	5,733,376	12,146	5,211,459	12,721
May-28	-	-	1,211,752	5,653,564	10,912	4,954,563	9,310	4,503,542	10,215
Jun-28	-	-	1,198,049	5,589,629	10,720	4,898,533	9,542	4,452,613	9,547
Jul-28	-	-	1,264,215	5,898,336	10,971	5,169,072	10,132	4,698,524	11,072
Aug-28	-	-	1,290,446	6,020,722	10,933	5,276,326	10,209	4,796,015	10,323
Sep-28	-	-	1,274,205	5,944,944	11,593	5,209,917	10,236	4,735,650	10,958
Oct-28	-	-	1,641,334	7,657,827	15,132	6,711,021	13,361	6,100,107	14,081
Nov-28	-	-	1,619,414	7,555,558	18,248	6,621,396	13,892	6,018,641	15,702
Dec-28	-	-	1,705,455	7,956,992	17,298	6,973,198	14,404	6,338,417	15,169
Jan-29	-	-	1,822,353	8,502,390	19,412	7,451,163	15,308	6,772,873	16,826
Feb-29	-	-	1,674,971	7,814,766	17,900	6,848,557	16,444	6,225,122	17,855
Mar-29	-	-	1,886,513	8,801,736	19,508	7,713,498	15,788	7,011,327	16,518
Apr-29	-	-	1,856,703	8,662,653	19,675	7,591,612	16,083	6,900,536	16,843
May-29	-	-	1,596,005	7,446,339	14,372	6,525,681	12,262	5,931,639	13,455
Jun-29	-	-	1,569,921	7,324,644	14,048	6,419,032	12,504	5,834,698	12,510
Jul-29	-	-	1,648,499	7,691,258	14,305	6,740,319	13,212	6,126,738	14,437
Aug-29	-	-	1,674,747	7,813,718	14,189	6,847,638	13,249	6,224,287	13,398
Sep-29	-	-	1,646,123	7,680,172	14,977	6,730,603	13,223	6,117,907	14,156
Oct-29	-	-	2,111,073	9,849,446	19,463	8,631,670	17,184	7,845,916	18,111
Nov-29	-	-	2,074,019	9,676,566	23,371	8,480,165	17,792	7,708,203	20,110
Dec-29	-	-	2,175,233	10,148,791	22,063	8,894,005	18,372	8,084,371	19,348

Renewable Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	(46,909.61)	0	(36,642.98)	(218,075.22)	(401)	(28,489.09)	(66)	0	0
Feb-25	(43,558.79)	0	(34,025.51)	(202,497.79)	(403)	(26,454.07)	(67)	0	0
Mar-25	(49,541.99)	0	(38,699.23)	(230,312.74)	(373)	(30,087.78)	(70)	0	0
Apr-25	(49,217.60)	0	(38,445.84)	(228,804.68)	(446)	(29,890.77)	(76)	0	0
May-25	(280,002.48)	0	(218,721.15)	(1,301,686.39)	(1,534)	(170,050.76)	(426)	0	0
Jun-25	(277,805.84)	0	(217,005.27)	(1,291,474.58)	(1,977)	(168,716.71)	(446)	0	0
Jul-25	(294,129.59)	0	(229,756.40)	(1,367,361.08)	(1,924)	(178,630.43)	(442)	0	0
Aug-25	(301,193.15)	0	(235,274.03)	(1,400,198.42)	(1,981)	(182,920.26)	(461)	0	0
Sep-25	(298,312.95)	0	(233,024.19)	(1,386,808.81)	(2,114)	(181,171.06)	(492)	0	0
Oct-25	(58,755.33)	0	(45,896.14)	(273,144.06)	(659)	(35,683.22)	(93)	0	0
Nov-25	(58,133.73)	0	(45,410.58)	(270,254.34)	(472)	(35,305.71)	(88)	0	0
Dec-25	(61,387.71)	0	(47,952.40)	(285,381.58)	(537)	(37,281.91)	(90)	0	0
Jan-26	(73,655.97)	0	(57,535.63)	(342,414.72)	(630)	(44,732.65)	(103)	0	0
Feb-26	(68,056.42)	0	(53,161.59)	(316,383.32)	(629)	(41,331.94)	(105)	0	0
Mar-26	(77,040.39)	0	(60,179.33)	(358,148.35)	(580)	(46,788.08)	(109)	0	0
Apr-26	(76,192.84)	0	(59,517.28)	(354,208.22)	(690)	(46,273.34)	(117)	0	0
May-26	(431,613.14)	0	(337,150.31)	(2,006,499.95)	(2,365)	(262,126.77)	(656)	0	0
Jun-26	(426,478.72)	0	(333,139.60)	(1,982,630.82)	(3,035)	(259,008.54)	(684)	0	0
Jul-26	(449,776.20)	0	(351,338.20)	(2,090,937.08)	(2,943)	(273,157.54)	(676)	0	0
Aug-26	(458,857.73)	0	(358,432.15)	(2,133,155.64)	(3,018)	(278,672.92)	(703)	0	0
Sep-26	(452,844.44)	0	(353,734.93)	(2,105,200.84)	(3,209)	(275,020.94)	(747)	0	0
Oct-26	(88,885.86)	0	(69,432.31)	(413,216.04)	(997)	(53,982.05)	(140)	0	0
Nov-26	(87,656.20)	0	(68,471.77)	(407,499.54)	(712)	(53,235.26)	(133)	0	0
Dec-26	(92,270.28)	0	(72,076.01)	(428,949.67)	(807)	(56,037.48)	(135)	0	0
Jan-27	(104,914.56)	0	(81,952.96)	(487,730.87)	(897)	(63,716.58)	(147)	0	0
Feb-27	(96,629.61)	0	(75,481.26)	(449,215.50)	(893)	(58,684.98)	(149)	0	0
Mar-27	(109,051.02)	0	(85,184.12)	(506,960.60)	(821)	(66,228.73)	(154)	0	0
Apr-27	(107,534.75)	0	(83,999.70)	(499,911.75)	(974)	(65,307.88)	(165)	0	0
May-27	(607,439.46)	0	(474,495.28)	(2,823,888.14)	(3,328)	(368,909.40)	(924)	0	0
Jun-27	(598,586.09)	0	(467,579.56)	(2,782,730.25)	(4,260)	(363,532.58)	(960)	0	0
Jul-27	(629,638.45)	0	(491,835.81)	(2,927,087.71)	(4,119)	(382,391.26)	(946)	0	0
Aug-27	(640,737.95)	0	(500,506.07)	(2,978,687.49)	(4,214)	(389,132.20)	(981)	0	0
Sep-27	(630,810.44)	0	(492,751.29)	(2,932,536.07)	(4,470)	(383,103.03)	(1,041)	0	0
Oct-27	(123,528.62)	0	(96,493.16)	(574,264.67)	(1,385)	(75,021.25)	(195)	0	0
Nov-27	(121,545.34)	0	(94,943.93)	(565,044.71)	(987)	(73,816.77)	(184)	0	0
Dec-27	(127,665.08)	0	(99,724.31)	(593,494.40)	(1,117)	(77,533.40)	(187)	0	0
Jan-28	(140,685.38)	0	(109,894.98)	(654,023.66)	(1,203)	(85,440.87)	(197)	0	0
Feb-28	(129,278.37)	0	(100,984.51)	(600,994.33)	(1,195)	(78,513.19)	(200)	0	0
Mar-28	(145,573.88)	0	(113,713.58)	(676,749.50)	(1,096)	(88,409.75)	(205)	0	0
Apr-28	(143,243.35)	0	(111,893.11)	(665,915.24)	(1,298)	(86,994.38)	(220)	0	0
May-28	(807,481.41)	0	(630,756.07)	(3,753,850.96)	(4,424)	(490,398.63)	(1,228)	0	0
Jun-28	(794,127.95)	0	(620,325.14)	(3,691,772.87)	(5,652)	(482,288.83)	(1,274)	0	0
Jul-28	(833,716.35)	0	(651,249.23)	(3,875,812.97)	(5,454)	(506,331.61)	(1,252)	0	0
Aug-28	(846,833.82)	0	(661,495.81)	(3,936,793.97)	(5,569)	(514,298.09)	(1,297)	0	0
Sep-28	(832,210.93)	0	(650,073.28)	(3,868,814.49)	(5,897)	(505,417.33)	(1,374)	0	0
Oct-28	(162,683.62)	0	(127,078.69)	(756,289.93)	(1,824)	(98,800.82)	(256)	0	0
Nov-28	(159,801.16)	0	(124,827.09)	(742,889.86)	(1,298)	(97,050.25)	(242)	0	0
Dec-28	(167,572.12)	0	(130,897.29)	(779,015.77)	(1,466)	(101,769.70)	(246)	0	0
Jan-29	(180,968.43)	0	(141,361.69)	(841,293.08)	(1,548)	(109,905.53)	(254)	0	0
Feb-29	(166,002.70)	0	(129,671.35)	(771,719.79)	(1,534)	(100,816.56)	(256)	0	0
Mar-29	(186,608.97)	0	(145,767.74)	(867,515.03)	(1,406)	(113,331.13)	(263)	0	0
Apr-29	(183,318.62)	0	(143,197.51)	(852,218.71)	(1,661)	(111,332.84)	(282)	0	0
May-29	(1,031,739.02)	0	(805,932.66)	(4,796,388.42)	(5,652)	(626,594.49)	(1,569)	0	0
Jun-29	(1,013,104.31)	0	(791,376.35)	(4,709,758.69)	(7,210)	(615,277.29)	(1,625)	0	0
Jul-29	(1,062,009.90)	0	(829,578.46)	(4,937,112.87)	(6,948)	(644,978.57)	(1,595)	0	0
Aug-29	(1,077,145.34)	0	(841,401.35)	(5,007,475.09)	(7,083)	(654,170.60)	(1,649)	0	0
Sep-29	(1,057,045.91)	0	(825,700.89)	(4,914,036.11)	(7,490)	(641,963.85)	(1,745)	0	0
Oct-29	(206,350.85)	0	(161,188.91)	(959,291.84)	(2,314)	(125,320.75)	(325)	0	0
Nov-29	(202,423.66)	0	(158,121.23)	(941,034.98)	(1,644)	(122,935.69)	(307)	0	0
Dec-29	(211,991.38)	0	(165,594.96)	(985,513.78)	(1,854)	(128,746.35)	(311)	0	0

Non-Renewable Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	0	0	(11,006)	(3,726,862)	(5,028)	(8,232,918)	(11,117)	(7,813,604)	(10,545)
Feb-25	0	0	(9,430)	(3,193,191)	(4,778)	(7,053,998)	(10,548)	(6,694,728)	(10,000)
Mar-25	0	0	(9,875)	(3,343,775)	(4,513)	(7,386,648)	(9,972)	(7,010,436)	(9,450)
Apr-25	0	0	(9,009)	(3,050,546)	(4,256)	(6,738,884)	(9,406)	(6,395,663)	(8,915)
May-25	0	0	(8,744)	(2,960,687)	(4,010)	(6,540,379)	(8,850)	(6,207,268)	(8,397)
Jun-25	0	0	(7,914)	(2,679,816)	(3,757)	(5,919,913)	(8,280)	(5,618,403)	(7,841)
Jul-25	0	0	(7,612)	(2,577,599)	(3,492)	(5,694,109)	(7,697)	(5,404,100)	(7,299)
Aug-25	0	0	(7,047)	(2,386,055)	(3,234)	(5,270,974)	(7,129)	(5,002,515)	(6,764)
Sep-25	0	0	(6,272)	(2,123,720)	(2,973)	(4,691,457)	(6,558)	(4,452,514)	(6,197)
Oct-25	0	0	(5,915)	(2,002,967)	(2,714)	(4,424,704)	(5,984)	(4,199,347)	(5,673)
Nov-25	0	0	(5,177)	(1,752,990)	(2,442)	(3,872,486)	(5,409)	(3,675,255)	(5,123)
Dec-25	0	0	(4,784)	(1,619,879)	(2,188)	(3,578,434)	(4,833)	(3,396,179)	(4,577)
Jan-26	0	0	(11,964)	(4,051,229)	(5,466)	(8,949,468)	(12,085)	(8,493,659)	(11,463)
Feb-26	0	0	(10,288)	(3,483,641)	(5,212)	(7,695,625)	(11,507)	(7,303,675)	(10,910)
Mar-26	0	0	(10,816)	(3,662,548)	(4,943)	(8,090,844)	(10,923)	(7,678,765)	(10,351)
Apr-26	0	0	(9,912)	(3,356,331)	(4,683)	(7,414,385)	(10,349)	(7,036,760)	(9,808)
May-26	0	0	(9,668)	(3,273,868)	(4,434)	(7,232,219)	(9,786)	(6,863,872)	(9,286)
Jun-26	0	0	(8,801)	(2,980,188)	(4,178)	(6,583,459)	(9,208)	(6,248,154)	(8,719)
Jul-26	0	0	(8,521)	(2,885,188)	(3,908)	(6,373,595)	(8,615)	(6,048,979)	(8,170)
Aug-26	0	0	(7,947)	(2,690,847)	(3,647)	(5,944,283)	(8,040)	(5,641,532)	(7,628)
Sep-26	0	0	(7,135)	(2,415,975)	(3,382)	(5,337,069)	(7,460)	(5,065,244)	(7,050)
Oct-26	0	0	(6,799)	(2,302,167)	(3,120)	(5,085,659)	(6,878)	(4,826,639)	(6,520)
Nov-26	0	0	(6,024)	(2,039,832)	(2,841)	(4,506,142)	(6,295)	(4,276,638)	(5,962)
Dec-26	0	0	(5,651)	(1,913,486)	(2,584)	(4,227,035)	(5,709)	(4,011,746)	(5,407)
Jan-27	0	0	(12,825)	(4,342,739)	(5,859)	(9,593,436)	(12,954)	(9,104,828)	(12,287)
Feb-27	0	0	(11,060)	(3,745,047)	(5,603)	(8,273,088)	(12,371)	(7,851,728)	(11,728)
Mar-27	0	0	(11,665)	(3,949,864)	(5,331)	(8,725,546)	(11,780)	(8,281,141)	(11,163)
Apr-27	0	0	(10,727)	(3,632,349)	(5,068)	(8,024,130)	(11,200)	(7,615,450)	(10,615)
May-27	0	0	(10,505)	(3,556,989)	(4,817)	(7,857,656)	(10,633)	(7,457,454)	(10,089)
Jun-27	0	0	(9,604)	(3,252,147)	(4,559)	(7,184,236)	(10,049)	(6,818,333)	(9,515)
Jul-27	0	0	(9,344)	(3,164,115)	(4,286)	(6,989,766)	(9,448)	(6,633,767)	(8,959)
Aug-27	0	0	(8,764)	(2,967,677)	(4,022)	(6,555,821)	(8,867)	(6,221,924)	(8,413)
Sep-27	0	0	(7,920)	(2,681,845)	(3,754)	(5,924,396)	(8,281)	(5,622,658)	(7,826)
Oct-27	0	0	(7,604)	(2,574,802)	(3,489)	(5,687,931)	(7,693)	(5,398,237)	(7,292)
Nov-27	0	0	(6,797)	(2,301,644)	(3,206)	(5,084,503)	(7,102)	(4,825,542)	(6,727)
Dec-27	0	0	(6,444)	(2,181,928)	(2,947)	(4,820,041)	(6,510)	(4,574,550)	(6,165)
Jan-28	0	0	(13,614)	(4,609,782)	(6,219)	(10,183,354)	(13,751)	(9,664,701)	(13,043)
Feb-28	0	0	(11,769)	(3,984,984)	(5,962)	(8,803,128)	(13,163)	(8,354,772)	(12,480)
Mar-28	0	0	(12,445)	(4,214,111)	(5,687)	(9,309,287)	(12,568)	(8,835,151)	(11,909)
Apr-28	0	0	(11,478)	(3,886,718)	(5,423)	(8,586,051)	(11,984)	(8,148,752)	(11,358)
May-28	0	0	(11,277)	(3,818,440)	(5,172)	(8,435,220)	(11,414)	(8,005,602)	(10,830)
Jun-28	0	0	(10,347)	(3,503,811)	(4,912)	(7,740,180)	(10,826)	(7,345,962)	(10,251)
Jul-28	0	0	(10,108)	(3,422,769)	(4,636)	(7,561,153)	(10,221)	(7,176,052)	(9,692)
Aug-28	0	0	(9,524)	(3,224,933)	(4,371)	(7,124,119)	(9,635)	(6,761,278)	(9,142)
Sep-28	0	0	(8,651)	(2,929,449)	(4,100)	(6,471,373)	(9,046)	(6,141,777)	(8,548)
Oct-28	0	0	(8,355)	(2,829,262)	(3,834)	(6,250,052)	(8,453)	(5,931,728)	(8,013)
Nov-28	0	0	(7,520)	(2,546,542)	(3,547)	(5,625,502)	(7,858)	(5,338,987)	(7,442)
Dec-28	0	0	(7,187)	(2,433,591)	(3,286)	(5,375,985)	(7,261)	(5,102,178)	(6,876)
Jan-29	0	0	(14,353)	(4,860,048)	(6,557)	(10,736,209)	(14,497)	(10,189,398)	(13,751)
Feb-29	0	0	(12,432)	(4,209,767)	(6,298)	(9,299,691)	(13,906)	(8,826,045)	(13,184)
Mar-29	0	0	(13,176)	(4,461,580)	(6,021)	(9,855,965)	(13,306)	(9,353,986)	(12,609)
Apr-29	0	0	(12,182)	(4,124,851)	(5,755)	(9,112,106)	(12,718)	(8,648,013)	(12,054)
May-29	0	0	(11,999)	(4,063,113)	(5,503)	(8,975,721)	(12,146)	(8,518,574)	(11,524)
Jun-29	0	0	(11,043)	(3,739,238)	(5,242)	(8,260,257)	(11,554)	(7,839,550)	(10,940)
Jul-29	0	0	(10,822)	(3,664,646)	(4,964)	(8,095,476)	(10,943)	(7,683,162)	(10,377)
Aug-29	0	0	(10,234)	(3,465,412)	(4,697)	(7,655,354)	(10,354)	(7,265,456)	(9,824)
Sep-29	0	0	(9,335)	(3,160,818)	(4,424)	(6,982,483)	(9,760)	(6,626,855)	(9,223)
Oct-29	0	0	(9,057)	(3,066,945)	(4,156)	(6,775,110)	(9,163)	(6,430,044)	(8,686)
Nov-29	0	0	(8,196)	(2,775,204)	(3,865)	(6,130,634)	(8,564)	(5,818,392)	(8,111)
Dec-29	0	0	(7,881)	(2,668,477)	(3,604)	(5,894,866)	(7,962)	(5,594,632)	(7,540)

Appendix B: Summary Curriculum Vitae

STEVEN A. FENRICK

SUMMARY OF EXPERIENCE AND EXPERTISE

- I have directed project teams and engaged in research in the fields of performance based regulation, performance benchmarking, DSM, load research and forecasting, and survey design and implementation.
- I have been a expert witness in a number of cases involving incentive regulation and other utility research topics.

PROFESSIONAL EXPERIENCE

Clearspring Energy Advisors, LLC (2019 to Present)

Principal Consultant

Responsible for providing consulting services and expert witness testimony to utilities and regulators in the areas of reliability and cost benchmarking, productivity studies and other empirical aspects of performance-based ratemaking and incentive regulation. Direct activities in the areas of demand-side management programs, peak time rebate programs, load forecasting, and market research.

Power System Engineering, Inc.– Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, ran peak time rebate programs, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling. Managed and supervised PEG support staff in research and marketing efforts.

EDUCATION

University of Wisconsin - Madison, WI

Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI

Master of Science, Agriculture and Applied Economics

Publications & Papers

- "Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- "Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)
- "Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).
- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", Utilities Policy, November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- "The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).
- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper.*
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.
- "Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism" *PSE whitepaper.*

Expert Witness Experience

- Docket EB-2021-0110, Hydro One Networks, Joint Rate Application for Transmission and Distribution. Custom Incentive Regulation Benchmarking and Productivity research.
- Case No. 2020-00299, Big Rivers Electric Corporation, Integrated Resource Plan. Testimony on load forecast research.
- Docket EB-2019-0261, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket EB-2019-0082, Hydro One Networks Transmission, TFP and Econometric Benchmarking research.
- Docket EB-2018-0165, Toronto Hydro Electric System Limited, Econometric Benchmarking research.
- Docket EB-2018-0218, Hydro One Transmission Sault St. Marie, TFP and Econometric Benchmarking research.
- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".
- Expert Witness presentation to Connecticut Governors "Two Storm Panel", 2012.
- Docket No. EB-2012-0064, Toronto Hydro's Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2019.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2018.
- Panel Moderator at WPUI conference on cost allocation and innovative rate designs at Madison WI. June 2018.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2017.
- Wisconsin Manager's Meeting, "Reliability Target Setting Using Econometric Benchmarking". November 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2016.

- Wisconsin Electric Cooperative Association (WECA) Conference, "An Introduction to Peak Time Rebates". September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2015.
- EUCI conference chair, 2015. "Evaluating the Performance of Gas and Electric Distribution Utilities."
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2014.
- Cooperative Exchange Conference, Williamsburg VA. "Smart Thermostat versus AC Direct Load Control Impacts". August 2014.
- EUCI conference chair in Chicago. "The Economics of Demand Response". February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2013.
- EUCI conference chair in Chicago. "Evaluating the Performance of Gas and Electric Distribution Utilities." August 2013.
- Presentation to the Ontario Energy Board, "Research and Recommendations on 4th Generation Incentive Regulation".
- Presentation to the Canadian Electricity Association's best practice working group. 2013
- Conference chair for EUCI conference in March 2013 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".
- Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.
- Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

OTHER REVENUE

1. INTRODUCTION

In addition to revenues recovered through distribution rates, Toronto Hydro earns other revenue from non-distribution related services, property and facility rentals, specific service charges, and short-term investments. Toronto Hydro also receives income and recoveries from shared services that it provides to its affiliates. Together, these revenues constitute Toronto Hydro's Other Revenue and reduce the utility's revenue requirement recovered through distribution rates. Other Revenue is broken out into the sub-categories summarized in Table 1 below.

Table 1: Other Revenue Summary

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Specific Service Charges	2.7	3.4	3.3	3.5	3.5	3.5	3.5	3.6	3.7	3.8
Late Payment Charges	2.1	1.7	3.5	4.9	4.6	3.9	4.0	4.1	4.2	4.2
Other Operating Revenues	26.4	27.4	27.5	26.5	27.3	28.1	28.7	29.3	29.9	30.5
Other Income or Deductions	8.1	7.5	13.1	11.3	11.5	12.4	12.6	12.8	13.0	13.3
Total	**39.3**	**40.0**	**47.4**	**46.2**	**46.9**	**47.9**	**48.8**	**49.8**	**50.8**	**51.8**

A complete breakdown of the Other Revenue accounts is shown in OEB Appendix 2-H – Other Operating Revenue (Exhibit 3, Tab 2, Schedule 2).

2. REVENUE FROM SPECIFIC SERVICE CHARGES

Toronto Hydro charges OEB-approved user fees for certain services. Some of these services, such as account set-up, are provided at the customer's request. Other fees result from Toronto Hydro's business operations, such as customers' non-payment of bills.

2020-2021 Variance Explanation

The historical variance between 2020 and 2021 actuals from $2.7 million to $3.4 million is primarily due to an increase in account setup charges driven by a higher volume of customer account set-up requests.

2021-2022 Variance Explanation

The historical variance between 2021 and 2022 actuals from $3.4 million to $3.3 million is primarily due to a decrease in account setup charges driven by a lower volume of customer account set-up requests.

2022-2025 Variance Explanation

The revenue from 2022-2025 is expected to remain stable in accordance with historical volumes of services driving specific service charges.

2025-2029 Variance Explanation

Between 2025 and 2029, revenue from specific service charges is expected to increase by $0.4 million, or an average of $0.1 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant growth in the volumes of services driving specific service charges.

3. LATE PAYMENT CHARGES

Toronto Hydro applies late payment charges on overdue customer balances in accordance with all applicable legislative and regulatory requirements.

2020-2021 Variance Explanation

The historical variance between 2020 and 2021 actuals from $2.1 million to $1.7 million is primarily due to Toronto Hydro's voluntary reduction of late payment charges as part of the relief provided to customers during the COVID-19 pandemic.[1]

2021-2022 Variance Explanation

The historical variance between 2021 and 2022 actuals from $1.7 million to $3.5 million is primarily due to the resumption of the standard late payment charge rate as the relief measures for customers were lifted by the end of COVID-19 pandemic.

2022-2025 Variance Explanation

Between 2022 and 2025, revenue from late payment charges is expected to significantly increase relative to previous years, as the arrears that customers accumulated over the COVID-19 pandemic cumulatively generate higher amounts of late payment charges. Toronto Hydro expects the increase in late payment charges to stabilize by 2025 as the utility's resumed collections efforts take effect and rein in the arrears caused by the pandemic.

2025-2029 Variance Explanation

Between 2025 and 2029, revenue from late payment charges is expected to increase by $0.3 million, or an average of less than $0.1 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant volumes of late or unpaid accounts.

[1] Refer to the Customer Care program in Exhibit 4, Tab 2, Schedule 14 for more information on Toronto Hydro's collections and disconnection for non-payment policies during the COVID-19 pandemic.

4. OTHER OPERATING REVENUES

Other Operating Revenues include revenues from Standard Supply Service ("SSS") administration charges, retail service charges, and maintenance of third-party facilities located within Toronto Hydro. It also includes revenues allocated from Toronto Hydro's contract with the City of Toronto for the maintenance of streetlighting assets.

2020-2021 Variance Explanation

The historical variance between 2020 and 2021 actuals from $26.5 million to $27.4 million is primarily due to an increase in revenues related to streetlighting assets and increased costs of streetlighting operations.

2021-2022 Variance Explanation

The historical variance between 2021 and 2022 actuals from $27.4 million to $27.5 million is primarily due to an increase in revenues related to streetlighting assets and increased costs of streetlighting operations.

2022-2025 Variance Explanation

Between 2022 and 2025, other operating revenues are expected to increase by $0.4 million, or an average of $0.1 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant growth in the volumes of services driving other operating revenues.

2025-2029 Variance Explanation

Between 2025 and 2029, other operating revenues are expected to increase by $2.3 million, or an average of $0.6 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant growth in the volumes of services driving other operating revenues.

5. OTHER INCOME OR DEDUCTIONS

Toronto Hydro earns revenue by providing services to customers and third parties, through gains on the sale of reclaimed materials from field, and gains on the disposal of utility property. Toronto Hydro also earns income and recoveries by providing shared services to its affiliates and through interest income from the short-term investment of idle cash balances.

Toronto Hydro divides its Other Income or Deductions into the following categories:

- Merchandise and Jobbing;
- Gains from Sale of Utility Properties;
- Shared Services Revenues and Expenses from Non-Rate-Regulated Utility Operations;
- Miscellaneous Non-Operating Income; and
- Interest Income from Short-Term Investment.

5.1 Merchandise and Jobbing

Toronto Hydro offers some services to customers and third parties for a fee. These services generally exclude those covered by the various OEB-approved specific service charges and are comprised of the following activities:

- Customer requests for isolations, protection, and temporary removals of lines to allow work on customer equipment;
- Repair of damaged distribution plant to be reimbursed by third parties (accident claims);

- Toronto Hydro's make-ready work and permit review for pole and duct attachments and rentals;
- Gains on sale of reclaimed materials from field; and
- Revenues from sale of inventory to third parties.

The revenues and expenses from Merchandise and Jobbing vary significantly from year to year, depending on the number and type of activities requested by customers. As such, forecast of the activities, revenues and expenses from 2023-2025 are based primarily on historical trends, 2025-2029 revenues and expenses forecasted in accordance with the growth of Toronto Hydro's customer base and concomitant volumes of merchandise and jobbing activities.

Toronto Hydro also generates income from the sale of reclaimed materials from field (e.g. scrap metals, reclaimed transformers, cables, etc.). These reclaimed materials are sold at market rates and any revenue depends on the strength of the market commodity prices at the time of disposition and the volume of reclaimed material that is available for processing. Toronto Hydro currently outsources the processing and selling of reclaimed materials to a third party. Proceeds of the sale net of the vendor's cost of disposing the reclaimed materials are remitted to Toronto Hydro.

5.2 Gains from Sale of Utility Properties

Toronto Hydro periodically disposes of surplus facilities, vehicles, and equipment. Over the 2020 to 2022 period, total net gains from sales were $3.6 million, of which the utility has recorded $1.6 million in the Gain on Sale of Property Variance Account in accordance with the OEB's decision from Toronto Hydro's 2020-2024 rate application.[2] For the forecast

[2] EB-2018-0165, Decision and Rate Order (February 20, 2020), Schedule C at pages 2-3. See Exhibit 9, Tab 1, Schedule 1 for more information on the Gain on Sale of Property Variance Account.

period of 2025 - 2029, Toronto Hydro forecasts gains on sale of utility properties of $1.8 million, which is in line with historical averages.

5.3 Shared Services Revenues and Expenses from Non-Rate-Regulated Utility Operations

Toronto Hydro provides shared services to its affiliates and receives income and recoveries through transfer prices determined based on Affiliate Relationship Code ("ARC") requirements. Further details on shared services are provided in Exhibit 4, Tab 5, Schedule 1.

5.4 Interest Income from Short-Term Investment

Toronto Hydro invests its working capital cash balances at a competitive market rate with its cash management bank to generate additional interest income. The interest earned from these short-term investment activities are an offset to Toronto Hydro's interest expense, which reduce the overall distribution revenue requirement and result in lower distribution rates, benefitting ratepayers.

5.5 Other Income or Deduction Year-over-Year Variance Analysis

2020-2021 Variance Explanation

The historical variance for other income or deductions between 2020 and 2021 actuals from $8.1 million to $7.5 million is due to:

- Decrease of $3.3 million in merchandising and jobbing primarily due to lower volume for accident claims, customer and temp services which was partially offset by higher revenues from sale of reclaimed materials.

These variances were partially offset by:

- Increase in gain on sale of property of $2.2 million,

- Increase in gain on foreign exchange and interest income from short-term investment of $0.6 million.

2021-2022 Variance Explanation

The historical variance for other income or deductions between 2021 and 2022 actuals from $7.5 million to $13.1 million is due to:

- Increase of $5.8 million in merchandising and jobbing primarily due to higher volume for customer and temp services and accident claims;
- Increase of $2.0 million primarily due to HST recovery from the Canada Revenue Agency relating to prior rate periods. Toronto Hydro expects this to be a one-time occurrence.

These variances were partially offset by:

- $2.3 million lower gain on sale of properties.

2022-2025 Variance Explanation

Between 2022 and 2025, other income or deductions are expected to be relatively lower by $0.7 million, or an average of $0.2 million per year, given that the peak in Other Income due to the one-time HST recovery is not expected to continue into 2023 or beyond. In addition, Toronto Hydro expects the revenues from merchandising and jobbing and gain on sale of properties to stabilize by 2023.

2025-2029 Variance Explanation

Between 2025 and 2029, other income or deductions are expected to increase by $0.9 million, or an average of $0.2 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant growth in the volumes of services driving other operating revenues.