Greater Toronto Area (GTA) East Integrated Regional Resource Plan (IRRP) Appendices

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Table of Contents

Appendix A – Overview of the Regional Planning Process **2**

Appendix B – Peak Demand Forecast **5**

B.1 Method for Accounting for Weather Impact on Demand 5

B.2 GTA East IRRP Forecast Methodology 6

B.3 Electricity Demand Side Management (eDSM) Assumptions 6

B.3.1 Estimated Savings from Building Codes and Equipment Standards 7

B.3.2 Estimated Savings from Electricity Demand Side Management Programs 7

B.3.3 Total eDSM Savings and Impact on the Planning Forecast 8

B.4 Installed Distributed Generation and Contribution Factor Assumptions 8

B.5 Final Peak Forecast by Station 9

B.6 Low and High Forecast Scenarios 9

Appendix C – IRRP Screening Mechanism **11**

Appendix D – Hourly Demand Forecast **14**

D.1 General Methodology 14

D.2 Subsystem Capacity Need 16

D.2.1 CTS Subsystem Supply Capacity Need 16

D.2.2 Whitby Subsystem Station Capacity Need 16

D.2.3 Wilson Subsystem Supply Capacity Need 17

Appendix E - Electricity Demand Side Management **19**

E.1 Provincial Achievable Potential Studies 19

E.2 Incremental Energy Savings Forecasts for the GTA East Region 20

Appendix F – Economic Assumptions **21**

F.1 General Assumptions 21

F.2 Transmission Assumptions 21

F.3 Resource Assumptions 21

Appendix A – Overview of the Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the OEB convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined. The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a needs assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a scoping assessment to determine what type of planning is required for a region. A scoping assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused regional infrastructure plan (RIP) can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at a minimum of every five years.

The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's websites and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, electricity Demand Side Management (eDSM), and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in **Figure 1**, three levels of electricity system planning are carried out in Ontario:

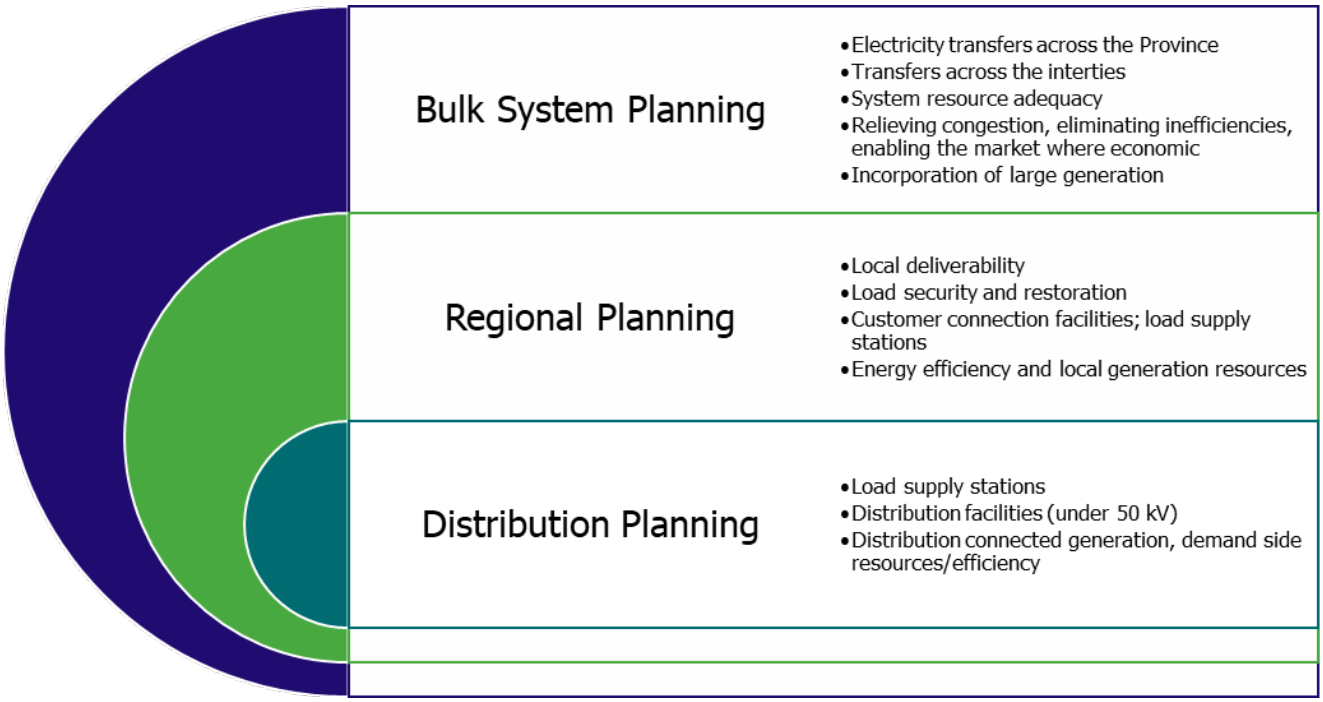
- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO. Distribution planning, which is carried out by LDCs, considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including additional eDSM, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Figure 1 | Levels of Electricity System Planning



Appendix B – Peak Demand Forecast

B.1 Method for Accounting for Weather Impact on Demand

Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for GTA East region's demand forecast.

First, the historical loads (2020-2024) were adjusted to reflect the median peak weather conditions for each transformer station in the area. Median peak refers to what peak demand would be expected if the "normal", or 50th percentile, weather conditions were observed. The 50th percentile is determined from a data set of the hottest or coldest day of each year for 30 historical years. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in **Figure 2.**

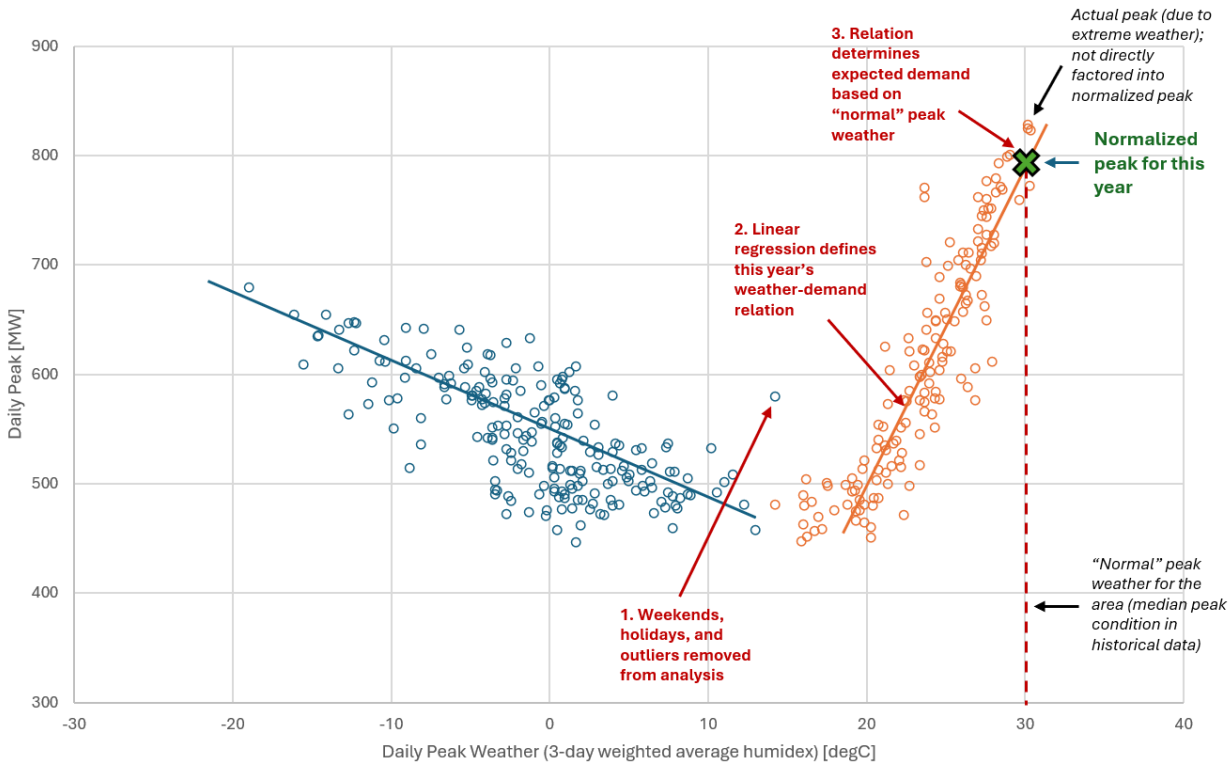
The historical median weather peak on a station and local distribution company (LDC) load basis was provided to each LDC. Average of 2021-2024[1] historical median weather summer and winter peak data was used as a starting point from which to develop 20-year demand forecasts, using the LDCs forecasting methodology of choice (described in the proceeding sections). The effects of Distributed Generation (DG) were added to the starting points before sending them out to the LDCs, so that a gross forecast may be provided back to the IESO.

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. To find extreme weather, the same process shown in **Figure 2** is completed. However, instead of using 50th percentile, the temperature of the hottest or coldest day in 30 years of historical data is used. The factors between the median peak and the extreme peak are recorded for the starting point years and averaged. This value is then used to convert the forecast to extreme weather conditions.

Subsequently, the impacts of estimated electricity Demand Side Management (eDSM) savings and Distributed Generation (DG) output were netted out of the forecast to create the final planning forecast. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest or coldest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves, winter cold waves) are generally when the electricity system infrastructure is most stressed.

[1] The 2020 historical data was excluded when establishing the forecast starting point due to atypical impacts of COVID-19.

Figure 2 | Method for Determining the Weather-Normalized Peak



B.2 GTA East IRRP Forecast Methodology

The GTA East IRRP forecast methodology document can be found on the IESO website.

B.3 Electricity Demand Side Management (eDSM) Assumptions

Electricity demand side management (eDSM) measures can reduce the electricity demand, and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and eDSM programs. The assumptions used for the GTA East IRRP forecasts are consistent with the eDSM assumptions in the IESO's 2025 Annual Planning Outlook. The savings between 2025 and 2044 were estimated by category according to the forecasted residential, commercial, and industrial gross demands. A top-down approach was used to estimate peak demand savings from the provincial level to the Toronto transmission zone and then allocated to the GTA East study region. This section describes the process and methodology used to estimate eDSM savings for the GTA East region of the study and provides more details on how the savings for the two categories were developed.

B.3.1 Estimated Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the study region, the associated peak demand savings for codes and standards by sector were estimated for the Toronto zone and compared with the gross peak demand forecast for the zone. From this comparison, annual peak reduction ratios were developed for the purpose of allocating the associated savings to each station in the region. The analyses were done for summer and winter separately and seasonal peak reduction ratios were estimated.

First, summer peak demand savings were estimated from summer gross demand forecast. New peak demand savings from codes and standards were estimated from 2025 to 2044. The residential summer peak reduction ratios of each year were applied to the forecasted residential summer peak demand at each station to develop an estimate of summer peak demand impacts from codes and standards. By 2044, the residential sector in the region is expected to see about 7.4% summer peak demand savings through codes and standards. The same is done for the commercial sector, which will see about 2.6% summer peak demand savings through codes and standards by 2044. No codes and standards savings were assumed for the industrial sector. The sum of the savings associated with the two sectors is the total summer peak demand impact from codes and standards.

The process was repeated for winter peak demand forecasts. By 2044, the residential sector and commercial sector in the region are expected to see about 7.2% and 1.7% respectively winter peak reductions through codes and standards.

B.3.2 Estimated Savings from Electricity Demand Side Management Programs

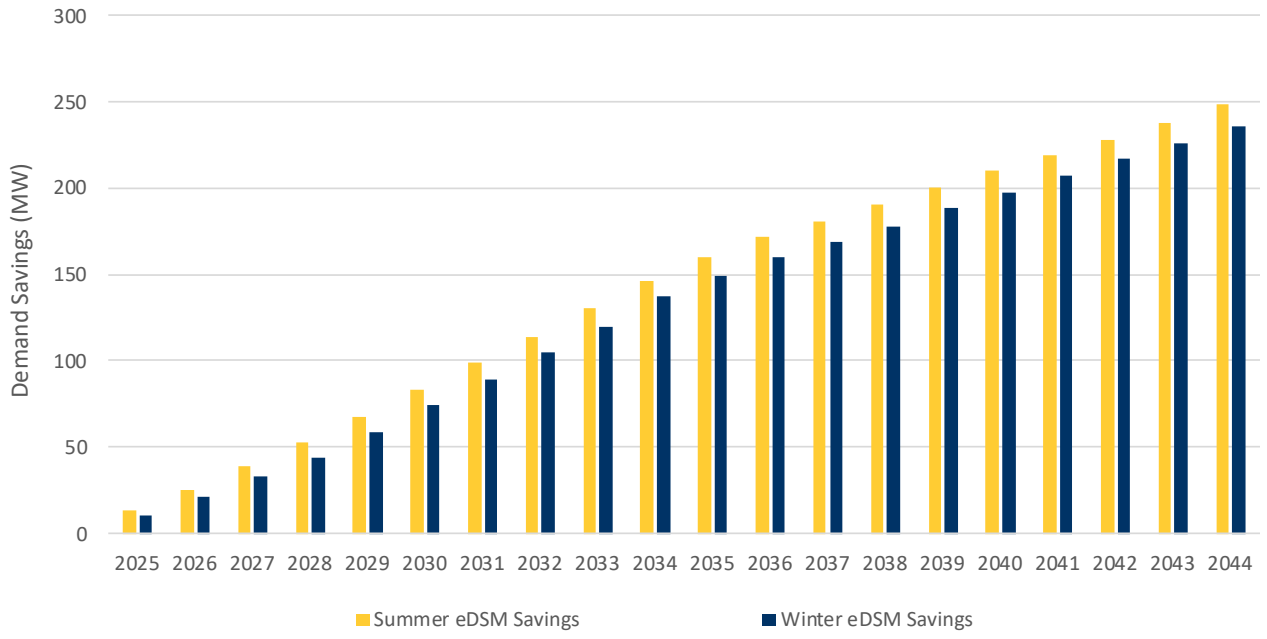
In addition to codes and standards, the delivery of eDSM programs reduces electricity demand. The impact of planned eDSM programs were analyzed, which is consistent with the 2025 Annual Planning Outlook. A top-down approach was used to estimate the peak demand reduction due to the delivery of these programs from the province to the Toronto transmission zone, and finally to the stations in the GTA East region. Persistence of the peak demand savings from eDSM programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, summer and winter peak demand reduction ratios from programs savings were developed by sector. The sectoral peak reduction ratios were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in the Toronto transmission zone. They were then applied to the sectoral gross peak forecast of each station in the study region. By 2044, the residential sector in the region is expected to see about 1.3% summer peak demand savings through programs while commercial sector and industrial sector will see about 16.4% and 9.4% summer peak reduction respectively. Winter peak reductions by 2044 were estimated as 2.3%, 12.9%, and 8.7% from residential, commercial, and industrial programs.

B.3.3 Total eDSM Savings and Impact on the Planning Forecast

As described in the above section, peak demand savings were estimated for each sector and totalled for each station in the region as shown in **Figure 3**. The analyses were conducted under normal weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

Figure 3 | Total eDSM Savings by Season



B.4 Installed Distributed Generation and Contribution Factor Assumptions

For the Distributed Generation (DG) contribution factor assumptions in winter and summer, refer to **Table 1**. For the installed DG output assumptions in winter and summer, refer to the GTA East IRRP Region Appendix Excel File.

Table 1 | Distributed Generation Contribution Factor by Resource Type and Season

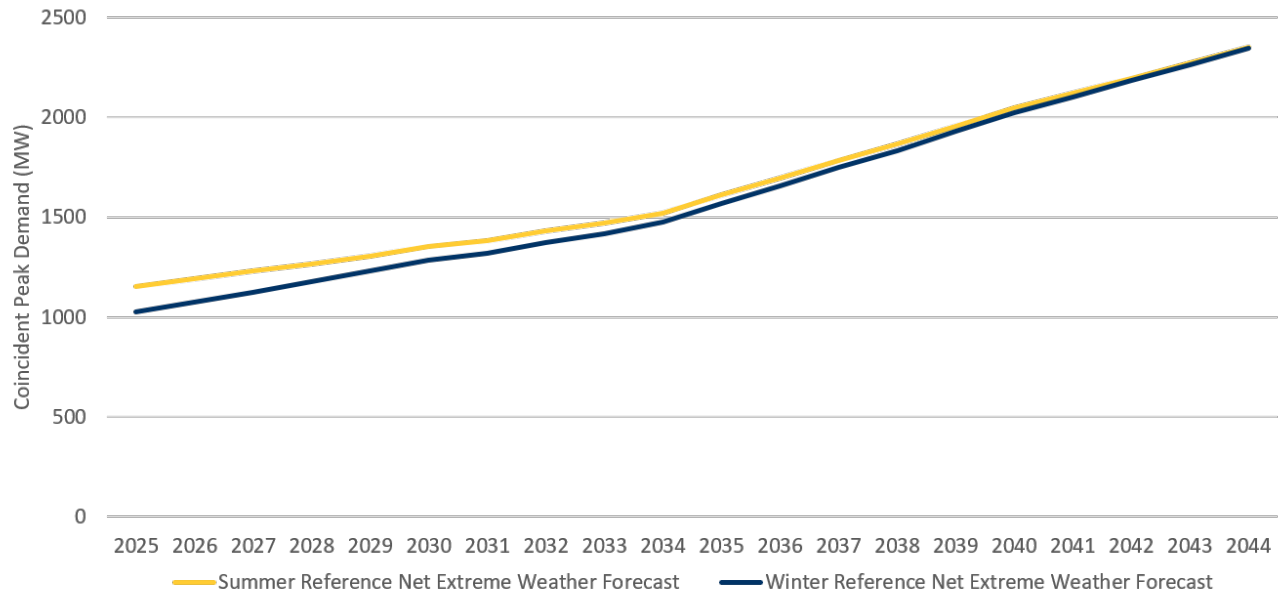
Type	Summer Contribution Factor	Winter Contribution Factor
Solar	25%	0%
Wind	16%	30%
Biomass	94%	94%
Gas	94%	94%

B.5 Final Peak Forecast by Station

After taking the median weather forecast provided from the LDCs, forecasts were adjusted to extreme weather. Then the eDSM and DG Assumptions above were applied to produce the final peak demand forecast.

As illustrated in **Figure 4**, coincident net peak demand under extreme weather conditions is forecast to increase by approximately 104% for summer and 129% for winter by 2044 under the reference scenario, indicating substantial load growth across the GTA East region. The final coincident and non-coincident peak demand forecasts are provided in tabular format in the GTA East Region IRRP Appendix Excel File.

Figure 4 | Summer and Winter Coincident Reference Forecast



B.6 Low and High Forecast Scenarios

As illustrated in **Figure 5** and **Figure 6**, under the low forecast scenario, coincident net peak demand under extreme weather conditions is projected to increase by approximately 70% for summer and 90% for winter by 2044. Under the high forecast scenario, coincident net peak demand is projected to increase by approximately 146% for summer and 170% for winter over the same period. These scenarios illustrate the range of potential load growth outcomes across the GTA East region. Final peak demand forecasts for both coincident and non-coincident demand are provided in tabular format in the GTA East Region IRRP Appendix Excel File.

Figure 5 | Summer Coincident Low, Reference, and High Forecast

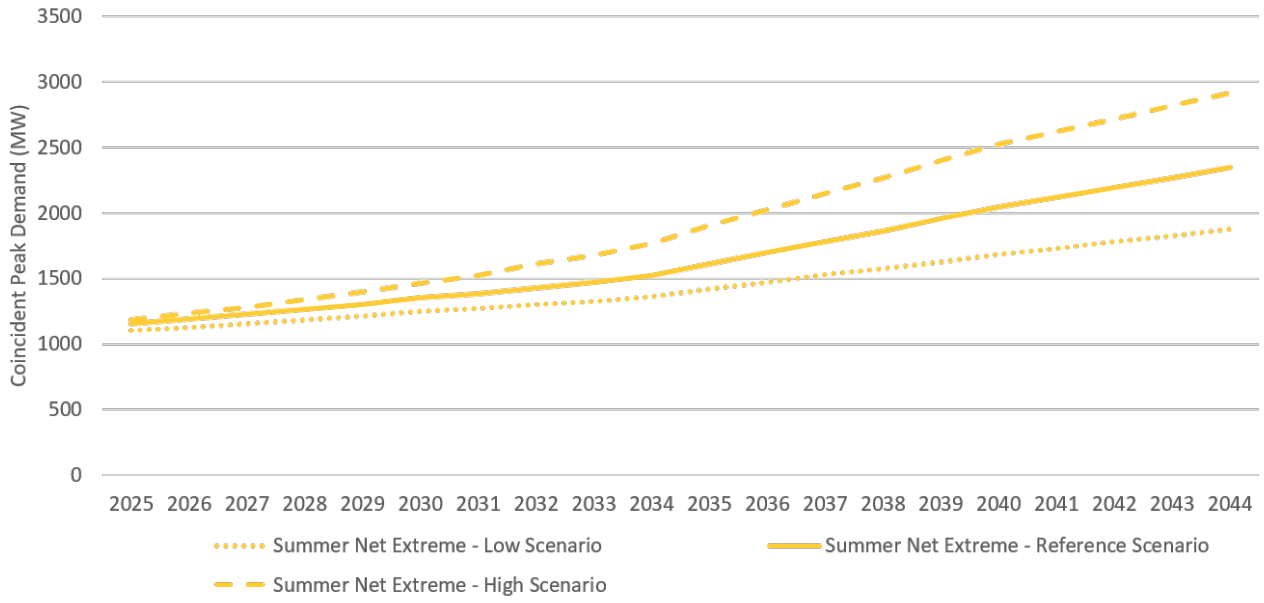
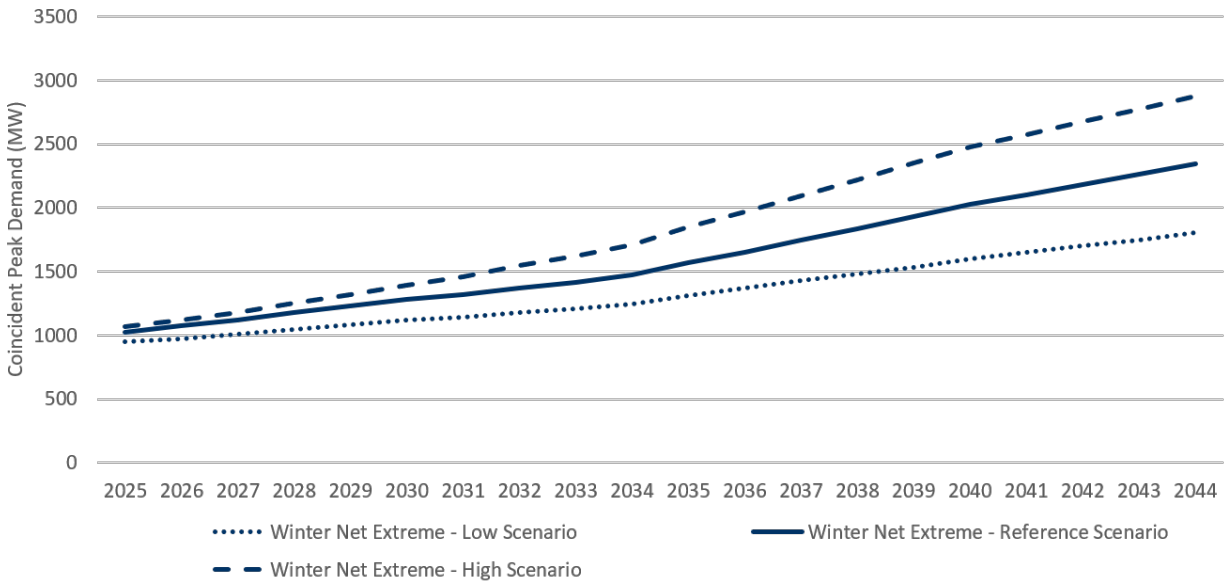


Figure 6 | Winter Coincident Low, Reference, and High Forecast



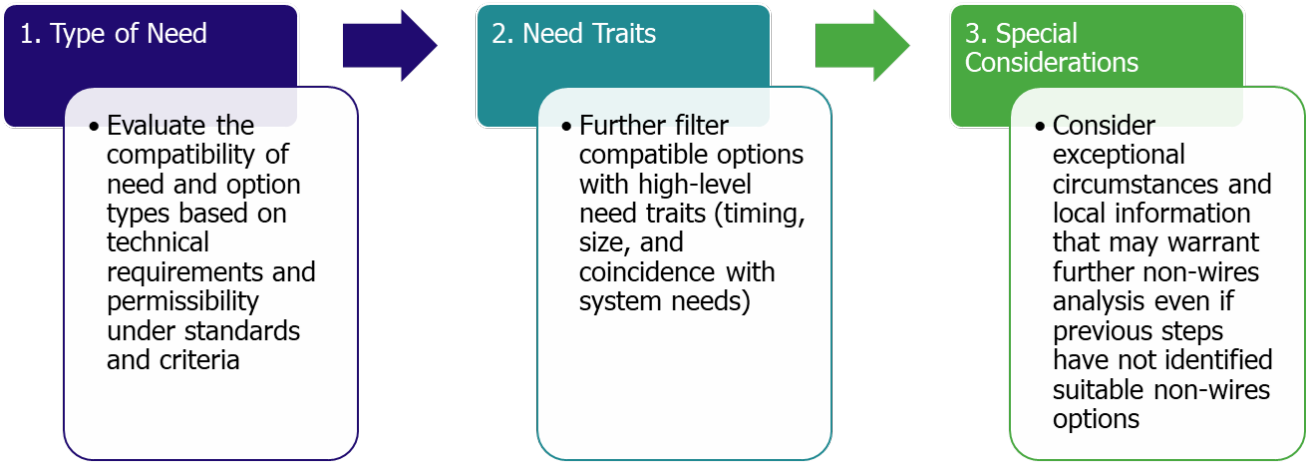
Appendix C – IRRP Screening Mechanism

The IESO developed a guide to the current general approach for evaluating non-wires alternatives (NWAs) during IRRPs. This guide summarizes various recent improvements made to better consider NWAs when developing an IRRP, including the process flow diagram, screening mechanism, hourly need characterization, development of options, and economic evaluation methodology. Planning participants and stakeholders can refer to this guide to better understand what key activities to expect during the IRRP.

An NWA screening step is carried out early in the IRRP development process after local reliability needs have been quantified but before options analysis begins. The screening mechanism provides a framework to identify suitable option types for the unique needs of each IRRP while improving transparency in the Technical Working Group's decision-making process, driving more consistency between different IRRPs, and focusing options analysis efforts on NWAs that are most likely to be feasible and cost-effective. The screening mechanism results in a shortlist of NWAs requiring further investigation. This list informs which local reliability needs require detailed hourly needs characterization, and maps candidate options to each need.

The screening mechanism is intended to be a guide rather than a strict set of criteria. It comprises three general steps that are summarized in **Figure 7**.

Figure 7 | IRRP NWAs Screening Mechanism



The first step in the screening mechanism is a general suitability filter that considers the type of need and the suitability of options according to its technical characteristics and permissibility under applicable planning criteria, such as the Ontario Resource and Transmission Assessment Criteria (ORTAC), North American Electric Reliability Corporation (NERC) TPL-001-5 and Northeast Power Coordinating Council (NPCC) Directory #1.

There are typically five types of needs identified through an IRRP: station capacity needs, supply capacity needs, asset replacement needs, load supply security needs, and load restoration needs. On the other hand, there are four categories of NWAs differentiated by operating characteristics (e.g., dispatchable vs. non-dispatchable), scalability, and treatment in current planning criteria. These include transmission-connected generation or energy storage, eDSM, distributed generation, and demand response. **Table 2** is the matrix used for the first step in the screening. After a shortlist of the need type/option type combinations has been produced, the second step of the screening mechanism further reduces this shortlist by considering the need's high-level characteristics, such as the size of the need and the coincidence with system peak. Step 2 is summarized in **Table 3**.

Table 2 | Screening Step 1: Suitability by Need and Option Type

Option \ Need	Supply Capacity	Station Capacity	Asset Replacement	Load Security	Load Restoration
Transmission-connected Resources	Yes	No	Yes	No	Yes
eDSM	Yes	Yes	Yes	No	No
Distributed generation	Yes	Yes	Yes	No	Yes
Demand response	Yes	Yes	Yes	No	No

Table 3 | Screening Step 2: Narrow Down Options Based on High-Level Need Traits

Option	Size of Need	Coincidence of the Need with System Peak
Transmission-connected Resources	Not applicable – always screened in	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
eDSM	Screened in if need is less than 2% of the load forecast in each year	Screened in only if coincident with system peaks
Distributed generation	Screened in if need is less than the available distributed generation connection space	Always screened in – generation can likely provide system value during provincial peaks even if local need is not coincident
Demand response	Screened in if need is proportional to the historically offered amount of demand response in the capacity auction	Screened in only if coincident with system peaks

The third and final step of the screening mechanism does not include a set of criteria – rather, it is to recognize the flexibility in IRRPs for exceptional circumstances and the uniqueness of each region. In some cases, special considerations could warrant further NWAs analysis regardless of the screening steps and outcomes described above. To account for the uniqueness of each region, the Technical Working Group considers factors including:

- Government policy or stakeholder support;
- Local preferences around solutions that the community will host;
- Unique load characteristics;
- Opportunities to explore a novel technology or operating model;
- Demand forecast uncertainty;
- Opportunities for integrated solutions; and,
- Availability of inexpensive and simple wires options that maximize the use of existing infrastructure.

Appendix D – Hourly Demand Forecast

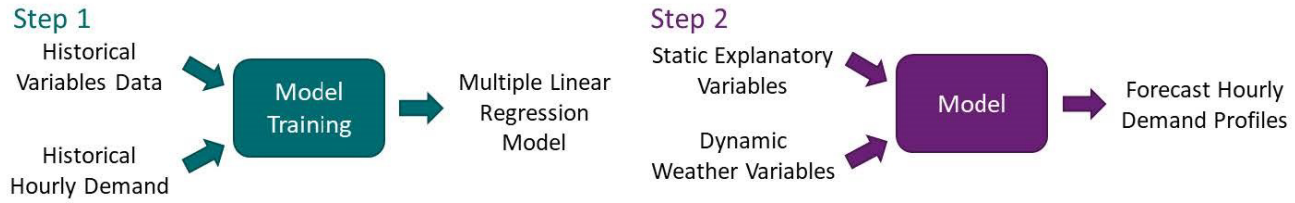
D.1 General Methodology

An hourly demand forecast consists of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are developed to help determine which non-wires alternatives may be best suited to meet regional needs.

For the GTA East Region IRRP, hourly load forecasting was completed on a subsystem basis, where there were capacity needs, or for stations with upstream supply capacity needs, that were screened in from the IRRP NWA screening mechanism in Appendix C. This consisted of Whitby subsystem, CTS subsystem, and Wilson subsystem as shown in the IRRP. Whitby subsystem consists of 230 kV stations Whitby TS T1/T2 (27.6kV and 44kV) and Whitby TS T3/T4. CTS subsystem consists of the 230 kV stations Thornton TS and CTS #1 to CTS #4. Wilson subsystem consists of Wilson TS T7/T8 and Wilson TS T3/T4. These three subsystems were identified as candidates for non wires through initial screening.

Forecasting was completed using a multi-variable linear regression with approximately five years' worth of historical hourly load data. The two-step approach to hourly forecasting in IRRPs is summarized in **Figure 8** and described further below.

Figure 8 | Summary of the Hourly Forecasting Methodology for IRRPs



First, a density-based clustering algorithm is used for filtering the historical data for outliers (including fluctuations possibly caused load transfers, outages, or infrastructure changes). Subsequently, the historical hourly data is combined with select predictor variables to perform a multi-variable linear regression and model the station's hourly load profile. The predictor variables are:

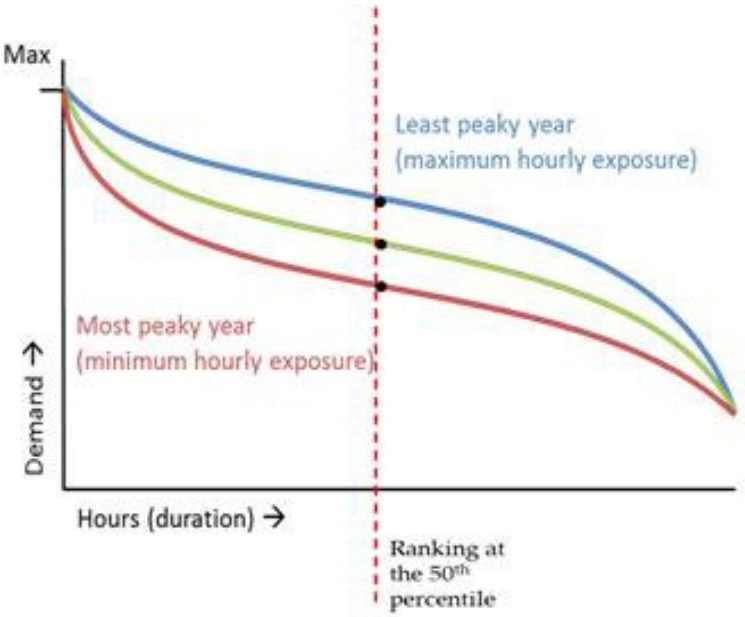
- Weather factors (temperature, cloud cover, humidity, and wind chill);
- Global horizontal irradiance;
- Econometric factors (population, employment);
- COVID-19 impacts; and
- Calendar factors (holidays and days of the week).

Model diagnostics (training mean absolute error, testing mean absolute error) are used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. Once the model is developed, it is applied with projections of the predictor variables. While future values for calendar and econometric variables are incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

To assess the impact that different weather sequences can have against the other non-weather variables, a set of several possible future hourly weather forecasts is produced. To start, the historical hourly weather data from the past 31 years is recorded, producing 31 annual hourly profiles (each profile consists of 8760 hours, covering 1 year). Then, each of these 31 profiles is shifted both ahead and behind by up to seven days. This process generates an additional 14 new profiles from each of the previous 31 profiles. This approach ultimately leads to 465 (31 + 14x31) possible hourly weather forecasts for each future year. For example, the set of possible weather on June 2nd, 2025, consists of the historical weather that occurred from every May 26th to June 9th over 1993 to 2023.

Subsequently, the set of 465 weather forecasts (together with the forecast of non-weather variables) are used to produce 465 load forecasts, which are ranked in ascending order based on their annual energy values. Load duration curves which illustrate this ranking can be seen in **Figure 9**. The forecast in the 50th percentile is the "Median Energy" (median profile, green curve) and is scaled so that its maximum matches the peak demand forecast.

Figure 9 | Illustrative Example: Ranking Hourly Load Profile by Energy



Hourly forecasts are a direct input for further NWAs assessments when combined with the relevant local transmission limits. The shape of the forecasted load that exceeds transmission limits is referred to as the need profile, or energy-not-served. Need profiles help identify key characteristics – the magnitude, frequency, and duration of possible need events, and how they could be dispersed over the days, months, and years in the 20-year planning horizon.

D.2 Subsystem Capacity Need

Figure 10 to **Figure 15** shows monthly and hourly heat maps produced for CTS, Whitby, and Wilson subsystem to illustrate capacity need characteristics in 2044 (long-term). Each cell in the heat map indicates the expected frequency (percentage of time) of a capacity need (demand in excess of limit) according to the month or hour.

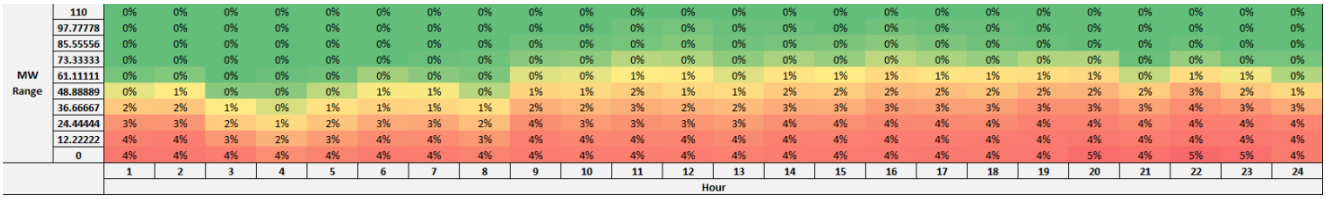
D.2.1 CTS Subsystem Supply Capacity Need

To read the heat maps, it is estimated that loading in the CTS subsystem exceeds the LMC by 73% of total hours in June 2044, as shown in the **Figure 10**. Load levels are estimated to exceed the LMC mainly in summer season (May to August). From an hourly perspective, needs are expected across all hours of the day, as shown in **Figure 11**.

Figure 10 | Monthly Heat Map of CTS Subsystem Need Magnitude in 2044

MW Range	1	2	3	4	5	6	7	8	9	10	11	12
110	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
97.77778	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
85.55556	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
73.33333	0%	0%	0%	0%	0%	1%	0%	1%	0%	0%	0%	0%
61.11111	0%	0%	0%	0%	0%	4%	2%	4%	1%	0%	0%	0%
48.88889	0%	0%	0%	0%	2%	8%	5%	8%	4%	2%	0%	0%
36.66667	0%	0%	0%	0%	6%	12%	9%	12%	9%	7%	0%	0%
24.44444	0%	0%	0%	0%	11%	15%	13%	14%	13%	12%	0%	0%
12.22222	0%	0%	0%	0%	15%	16%	15%	16%	15%	15%	0%	0%
0	1%	1%	0%	0%	16%	17%	16%	17%	16%	16%	0%	0%
	Month											

Figure 11 | Hourly Heat Map of CTS Subsystem Need Magnitude in 2044



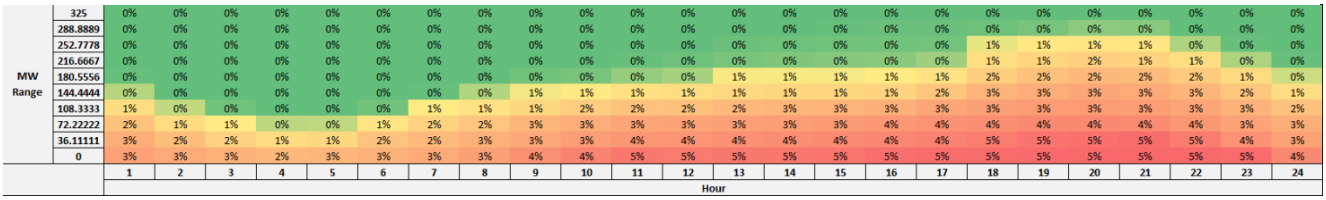
D.2.2 Whitby Subsystem Station Capacity Need

For the Whitby subsystem, it is estimated that its loading exceeds the combined LTR by 53% of total hours in January 2044, as shown in the **Figure 12**. Load levels are estimated to exceed the combined LTR across the season but more significantly in the winter season (November to April). From an hourly perspective, needs are seen across all hours of the day, with significant amounts of need expected in the hours between 18 to 21 as shown in **Figure 13**.

Figure 12 | Monthly Heat Map of Whitby Subsystem Need Magnitude in 2044

MW Range	1	2	3	4	5	6	7	8	9	10	11	12
325	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
288.8889	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
252.7778	1%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	1%
216.6667	2%	1%	1%	0%	0%	0%	0%	1%	0%	0%	0%	2%
180.5556	4%	2%	2%	0%	0%	0%	0%	2%	0%	0%	1%	4%
144.4444	7%	4%	3%	2%	0%	1%	0%	3%	0%	0%	2%	6%
108.3333	8%	7%	7%	4%	0%	1%	1%	5%	1%	0%	4%	8%
72.22222	10%	8%	9%	7%	0%	2%	3%	6%	3%	0%	7%	9%
36.11111	10%	9%	10%	9%	1%	3%	5%	7%	5%	2%	8%	10%
0	11%	10%	11%	10%	4%	5%	7%	9%	7%	6%	10%	11%
	Month											

Figure 13 | Hourly Heat Map of Whitby Subsystem Need Magnitude in 2044



D.2.3 Wilson Subsystem Supply Capacity Need

For the Wilson subsystem, it is estimated that its loading in the Wilson subsystem area exceeds the LMC by 37% of total hours in July as shown in **Figure 14**. Load levels are estimated to exceed the LMC across all seasons but more significantly in the summer season (May to August). From an hourly perspective, needs are expected across all hours of the day with more frequent need in the hours between 18 to 21, as shown in **Figure 15**.

Figure 14 | Monthly Heat Map of Wilson Subsystem Need Magnitude in 2044

MW Range	1	2	3	4	5	6	7	8	9	10	11	12
355	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
315.5556	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
276.1111	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
236.6667	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
197.2222	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%
157.7778	2%	0%	0%	0%	0%	2%	3%	1%	0%	0%	0%	0%
118.3333	4%	2%	0%	0%	0%	3%	5%	2%	0%	0%	0%	2%
78.88889	8%	4%	1%	1%	0%	4%	6%	3%	0%	0%	1%	5%
39.44444	11%	8%	4%	3%	0%	6%	8%	6%	1%	1%	4%	8%
0	14%	12%	8%	7%	1%	8%	10%	9%	5%	4%	9%	13%
	Month											

Figure 15 | Hourly Heat Map of Wilson Subsystem Need Magnitude 2044

MW Range	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
355	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
315.5556	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
276.1111	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
236.6667	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
197.2222	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%
157.7778	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%
118.3333	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	1%	0%
78.88889	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	2%	2%	2%	2%	3%	3%	4%	3%	3%	2%	1%
39.44444	2%	1%	0%	0%	0%	0%	1%	1%	1%	2%	2%	2%	3%	3%	3%	4%	4%	5%	5%	5%	5%	4%	4%	3%
0	3%	2%	2%	1%	1%	2%	3%	3%	3%	4%	4%	5%	5%	5%	5%	6%	6%	6%	6%	7%	7%	6%	5%	4%

Hour

Appendix E - Electricity Demand Side Management

E.1 Provincial Achievable Potential Studies

Electricity Demand Side Management (eDSM) is a lower-cost resource that offers significant potential benefits to individuals, businesses, and the electricity system as a whole. Targeted additional eDSM in areas of the province with regional and local needs can help offset investments in new resources or transmission, defer this spending to a later date, and/or can complement these investments as part of an integrated solution for the area.

To understand the scale of opportunity and associated costs for targeted eDSM in a local area, data and assumptions can be leveraged from provincial eDSM potential forecasts. In 2019, the IESO and the OEB completed the first integrated electricity and natural gas achievable potential study in Ontario ("2019 APS"). The main objective of the APS was to identify and quantify energy savings potential (for both electricity and natural gas), greenhouse gas emission reductions, and associated costs from demand-side resources for the period from 2019-2038 under different scenarios. This achievable potential modelling is used to inform:

- Future energy efficiency policy and/or frameworks;
- Program design and implementation; and
- Assessments of eDSM non-wires potential in regional planning.

The 2019 APS determined that both electricity and natural gas have significant cost-effective energy efficiency potential in the near and longer terms. In particular, the maximum achievable potential scenario is one scenario in the APS that estimates the available potential from all eDSM measures that are cost-effective from the provincial system perspective, i.e., they produce benefits from avoided energy and system capacity costs that are greater than the incremental costs of implementing the measures.

The results of the 2019 APS were updated with the 2022 Achievable Potential Study ("2022 APS"). The 2022 APS shows that under the maximum achievable potential scenario, eDSM measures have the potential to reduce summer electricity peak demand up to 3,500 MW in the province over the 20-year forecast period and can produce up to 28 TWh of energy savings over the same period.

After scaling this level of forecasted maximum achievable savings potential to the local area, the forecasted savings that are expected to come from existing provincial and federal eDSM programs, the forecasted savings that are expected to come from future anticipated eDSM programs, as well as savings from codes and standards, are netted out and the remaining achievable savings potential were identified. The remaining potential provides an estimate of the amount of incremental cost-effective eDSM savings potential that can help address emerging local needs.

E.2 Incremental Energy Savings Forecasts for the GTA East Region

The East zonal rates of savings potential from the last provincial APS were applied to the demand forecasts to determine the maximum achievable potential eDSM savings for the stations in the GTA East region. Through the screening process, only the following stations were applicable for additional eDSM savings: Cherrywood TS, Whitby TS, Thornton TS, and Wilson TS.

At the Pickering-Ajax-Whitby Subregion, shown in **Figure 16**, about 55 MW of incremental eDSM savings potential is estimated to be achieved in 2042. The estimated cost to deliver these savings is about $180 million dollars over the forecast period based on APS cost assumptions.

At the Oshawa-Clarington Subregion, shown in **Figure 17**, about 20 MW of incremental eDSM savings potential is estimated to be achieved in 2042. The estimated cost to deliver these savings is about $60 million dollars over the forecast period based on APS cost assumptions.

Figure 16 | Incremental Summer eDSM Savings Potential at Pickering-Ajax-Whitby Subregion

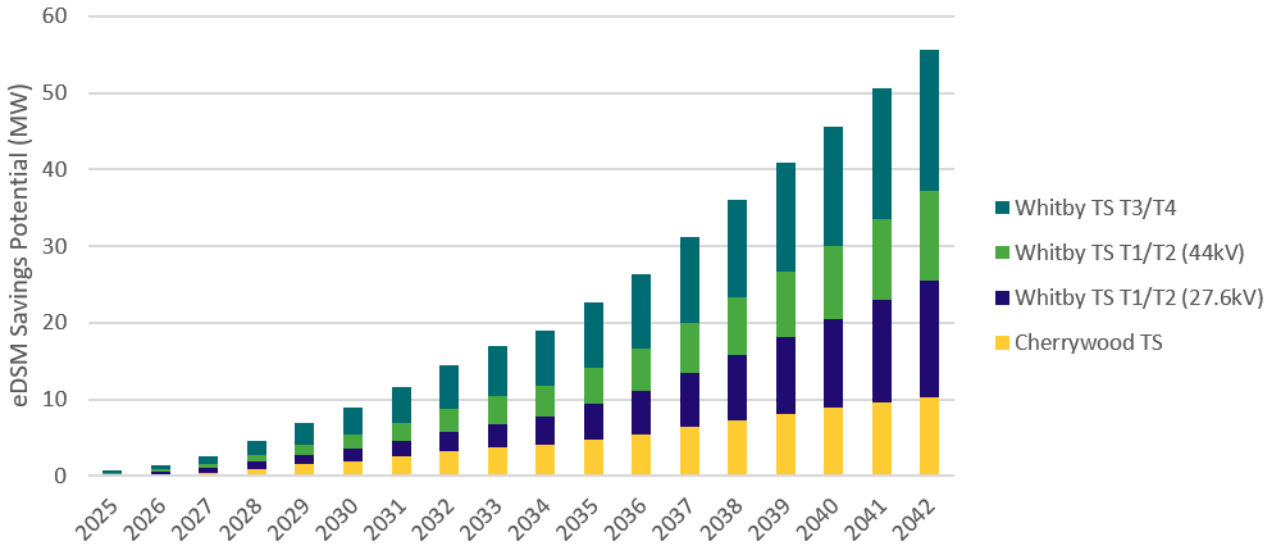
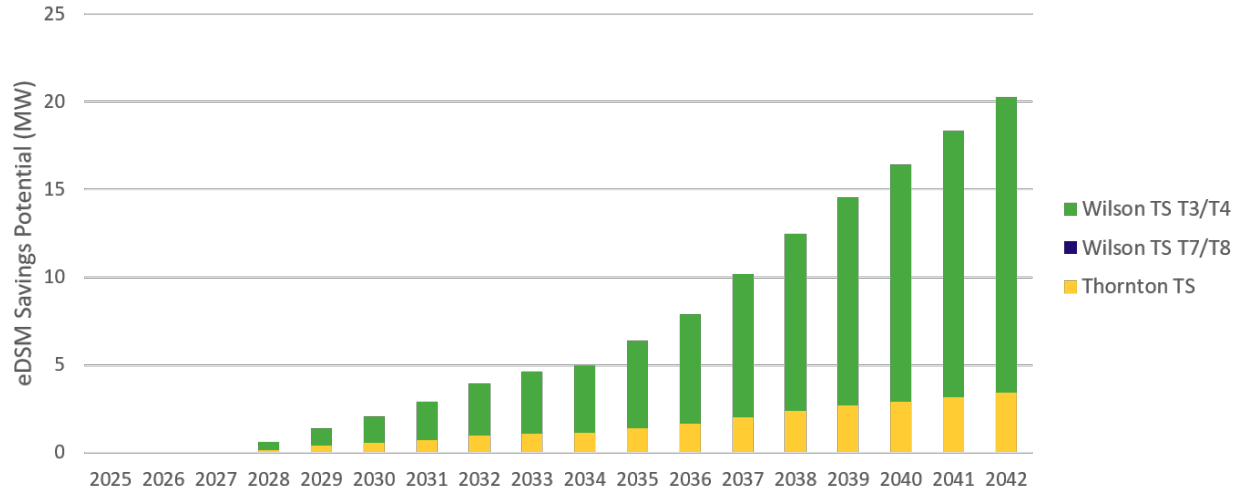


Figure 17 | Incremental Summer eDSM Savings Potential at Oshawa-Clarington Subregion



Appendix F – Economic Assumptions

The following subsections provide a list of the assumptions made in the economic analysis for options considered in the IRRP.

F.1 General Assumptions

- The net present value (NPV) of the cash flow is expressed in 2026 CAD.
- The NPV analysis was conducted using a 4% real social discount rate. An annual inflation rate of 2% was assumed. Note that NWA solutions are presented in terms of NPV and Transmission solutions were also presented in terms of estimated capital cost.
- The NPV study period for the options analysis started the year that the option could feasibly come into service and assumed a useful service life covering the life of the asset until the point at which an asset replacement decision would be required.
- The useful service life of station assets was assumed to be 40 years, and the useful service life of transmission line assets was assumed to be 70 years.
- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

F.2 Transmission Assumptions

Capital costs for the transmission options were determined based on estimates of: $6-8M/km to either install a new double circuit 230 kV line or upgrade an existing double circuit 115 kV line to 230 kV; $5M/km to uprate existing 115 kV lines to higher ampacity lines; $60 M/DESN for new 44kV substation DESNs, and $60M per dynamic voltage support devices (SVC, STATCOM, condenser). This was informed by cost estimates in the Leave to Construct application evidence on file with the Ontario Energy Board, benchmark transmission costs, as well as the input received from Hydro One. A -50% and +100% contingency was assumed for the purpose of this analysis.

Specific costs from specific projects were also provided by Elexicon and is summarized below:

- North Whitby/Pickering TS: $85 million for a new DESN

F.3 Resource Assumptions

- Overnight capital costs and operating costs for wind, solar and BESS are based on Ontario-specific benchmark forecasts, and accounts for the impact of the Clean Investment Tax Credit.
- Plexos capacity expansion model is used to develop the non-emitting resources required to meet the identified hourly needs. Plexos production cost model of 99.9% of load served, confirmed by Plexos production cost model, was considered necessary in the peak need year for the NWA to be considered a feasible option.

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