Toronto Integrated Regional Resource Plan Appendices

July 2026

Connecting Today.
Powering Tomorrow.

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Appendix A – Overview of the Regional Planning Process

Ontario's regional planning process is designed to ensure that electricity infrastructure continues to meet customer needs reliably and cost-effectively in the face of changing demand, economic growth, electrification, and evolving technologies. Regional planning evaluates electricity needs over the near, medium, and long-term horizons and identifies appropriate solutions that may include transmission infrastructure, local distribution investments, energy efficiency, demand response, distributed energy resources (DERs), electricity storage, and/or generation resources. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, and evaluate and recommend actions for addressing needs.

Regional planning is conducted across 21 planning regions in Ontario and is coordinated by the Independent Electricity System Operator (IESO), transmitters, and local distribution companies (LDCs) through a Technical Working Group (TWG). Municipalities, Indigenous communities, customers and other stakeholders contribute to the planning process through engagement activities that help inform forecasts, assumptions, local priorities and potential solutions. The process is intended to provide a transparent and coordinated approach to identifying electricity system needs and developing recommendations to address them.

The regional planning framework was established by the Ontario Energy Board (OEB) in 2013 through amendments to the Transmission System Code and Distribution System Code, following recommendations from the Planning Process Working Group (PPWG). Since its implementation, the process has undergone several enhancements to improve coordination with municipalities, Indigenous communities, electricity distributors, and other planning initiatives. The province is currently in the third cycle of regional planning activities.

The regional planning process consists of four primary stages: the Needs Assessment, a Scoping Assessment, Integrated Regional Resource Plan (IRRP), and Regional Infrastructure Plan (RIP).

Needs Assessment

The regional planning process begins with a Needs Assessment developed by the TWG, with the transmitter leading the assessment. The Needs Assessment considers forecast electricity demand, asset conditions, and reliability performance to determine whether there is emerging needs requiring regional coordination. If regional needs are identified, the IESO carries out the next phase of regional planning, a Scoping Assessment, to determine what type of planning is required for a region. If regional needs requiring coordination are identified, the IESO undertakes a Scoping Assessment to determine the most appropriate planning approach. If the Needs Assessment determines that regional coordination is not required, the regional planning cycle continues directly to a Regional Infrastructure Plan (RIP), which documents local infrastructure needs and planned investments.

Scoping Assessment

Where regional coordination is required, the IESO leads a Scoping Assessment to determine the most appropriate planning approach. This assessment examines whether the identified needs would benefit from:

- an IRRP: evaluates both wires and non-wires solutions, including conservation, energy efficiency, demand response, distributed energy resources, generation, transmission and distribution options.
- a RIP: focuses on transmission and distribution infrastructure solutions.
- Local planning: addresses needs through coordination between the transmitter and distributor without additional regional planning.

A draft Scoping Assessment Outcomes Report is posted for public review and comment before being finalized. The results of the Scoping Assessment are contained a report that includes the results of the Needs Assessment process and a preliminary Terms of Reference, for an IRRP, if an IRRP is identified as the most appropriate planning approach.

Integrated Regional Resource Plan

Where an IRRP is recommended, the IESO leads the development of the plan through the TWG comprised of the IESO, the transmitter(s), and the affected LDCs. The TWG is responsible for assessing regional needs, evaluating alternatives, and developing recommendations to address identified reliability and capacity requirements. IRRP's are required to be completed within 18 months of initiation, with the ability to extend to 24 months if necessary to complete and fully engage on the plan.

IRRPs consider:

- Electricity demand forecasts and electrification trends;
- "Wires" solutions including transmission and distribution investments;
- "Non-wires" solutions including additional eDSM (beyond already planned programming), Distributed Energy Resources, and demand response in combination with supply resources and community and stakeholder objectives. Supply resources would include commercially viable options for the need which are reasonably feasible from an implementation perspective. Types of supply resources can include solar, wind, natural gas, hydro-electric, and energy storage systems.

Throughout the IRRP process, the IESO undertakes engagement with municipalities, Indigenous communities, customers, developers, community organizations, and other interested parties. Feedback received through engagement activities helps inform the planning process by providing information on projected growth, electrification initiatives, community priorities, and potential local solutions.

Regional Infrastructure Plan

The final phase of regional planning is the RIP, led by the transmitter. The RIP develops and evaluates transmission and distribution alternatives and identifies recommended infrastructure investments. A RIP must be completed within six months of initiation. Both RIPs and IRRPs are to be updated at a minimum of every five years.

Relationship to Other Planning Processes

Regional planning is one component of Ontario's broader electricity planning framework, which also includes:

- Bulk system planning: province-wide planning of the transmission system and provincial electricity resources, generally focused on the 230 kV and 500 kV networks.
- Regional system planning: coordinated planning of regional electricity needs and infrastructure.
- Distribution system planning: local planning undertaken by electricity distributors to meet customer needs within their service territories.

Regional planning serves as a link between bulk and distribution planning by coordinating regional needs and identifying integrated solutions that optimize reliability, flexibility and cost-effectiveness for electricity consumers.

The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are ae made publicly available and may support future infrastructure regulatory applications, eDSM and/or DER programs and procurements, municipal planning activities, and First Nation and Métis community energy planning initiatives.

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 promotes transparency, coordination and informed decision-making while supporting Ontario's evolving electricity system and future growth.

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 regional demand forecasts.

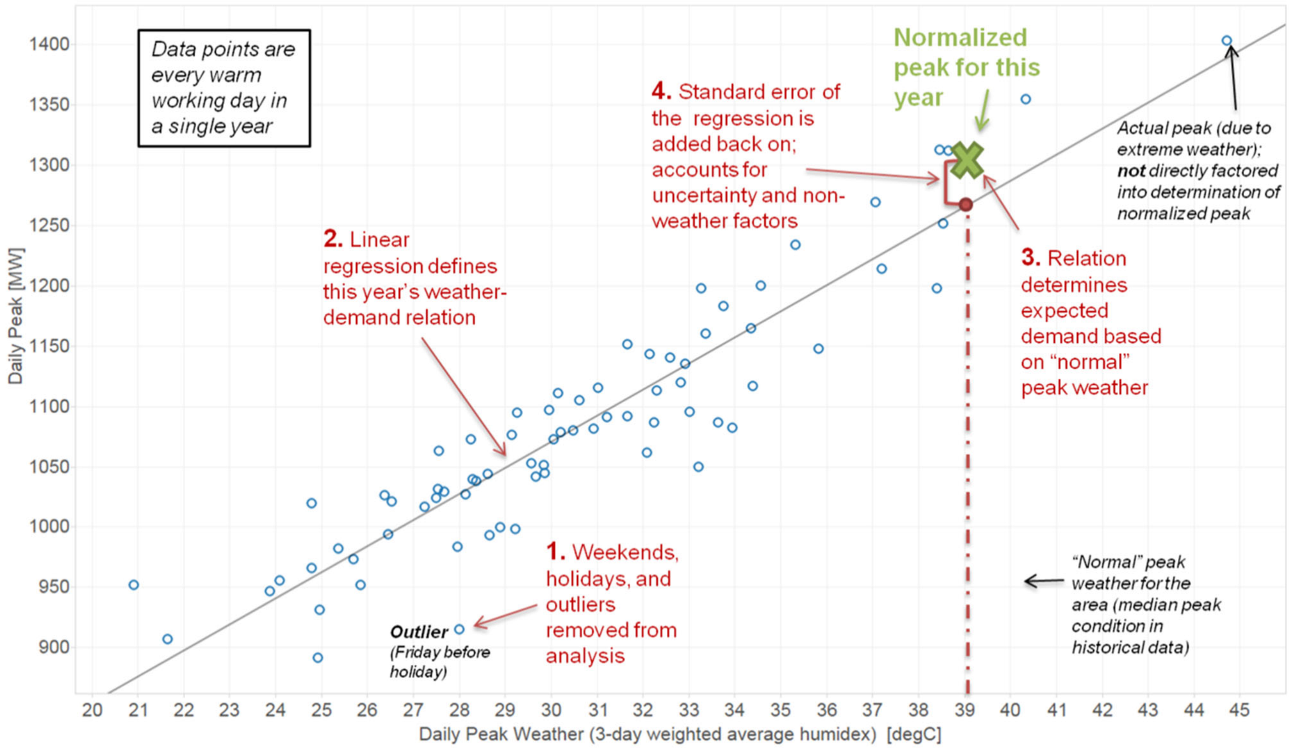
First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (in this case 2022). Median peak refers to what peak demand would be expected if the "normal", or 50th percentile, weather conditions were observed. The 50th percentile is determined from a data set of the hottest 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 1.

The 2022 median weather peak on a station and local distribution company (LDC) load basis was provided to each LDC. This 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 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 1 is completed. However, instead of using 50th percentile, the temperature of the hottest 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 DG output were netted out of the forecast to create the final net 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 weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves) are generally when the electricity system infrastructure is most stressed.

Figure 1 | Method for Determining the Weather-Normalized Peak



B.2 Toronto IRRP Forecast Methodology

The [Toronto IRRP forecast methodology document] can be found on the IESO website.

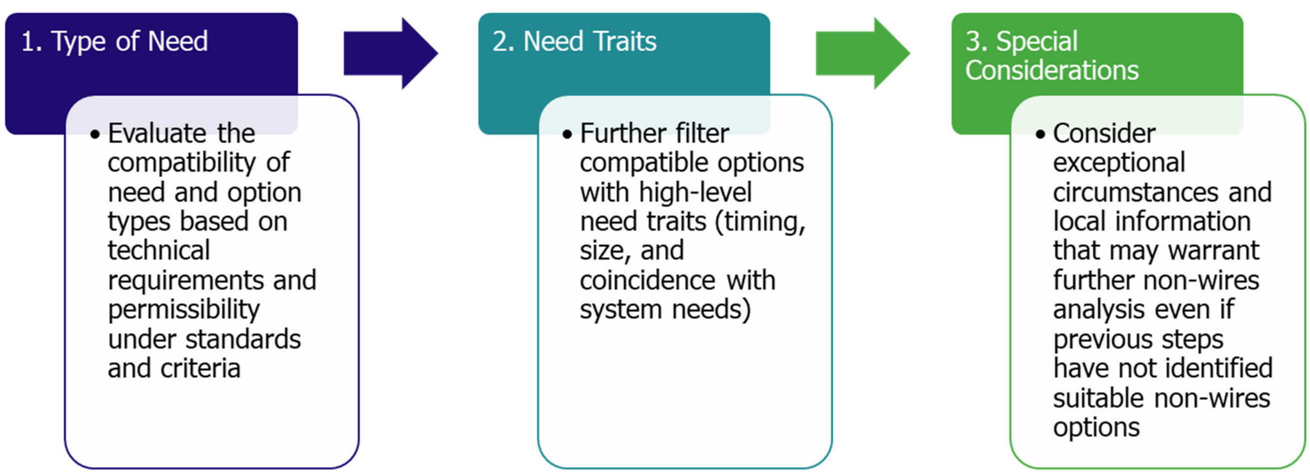
Appendix C – IRRP Screening Mechanism

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 needs 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 in the IRRP development process after local reliability needs have been quantified and before options analysis is done. The screening mechanism provides a framework to identify suitable option types for the unique regional power system needs of each IRRP. It is intended to improve transparency in the Technical Working Group's decision-making process, drive more consistency between different IRRPs, and focus options analysis efforts on NWAs that are most likely to be technically 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 2.

Figure 2 | 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-001-5.1, 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 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, DG, and demand response.

Table 1 shows 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 2.

Table 1 | 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 2 | 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 may consider factors such as:

- 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 options may be best suited to meet regional needs.

For the Toronto IRRP, hourly load forecasting was completed on a subsystem basis, focusing on groups of stations where there were capacity needs or stations with upstream transmission supply capacity needs. These would have been screened in from the IRRP NWA screening mechanism described in Appendix C, and identified as candidates for non-wires alternatives.

Forecasting was completed using a multi-variable linear regression using approximately five years of historical hourly load data. This two-step approach to hourly forecasting in IRRPs is summarized in Figure 3 and is described further below.

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 was produced. To start, the historical hourly weather data from the past 31 years was recorded, producing 31 annual hourly profiles (each profile consists of 8760 hours, covering 1 year). Then, each of these 31 profiles was shifted both ahead and behind by up to seven days. This process generated an additional 14 new profiles from each of the previous 31 profiles. This approach ultimately resulted in 465 (31 + 14 x 31) possible hourly weather forecasts for each future year. For example, using this method the set of possible weather on June 2, 2025 would consist 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) were used to produce 465 load forecasts, which were ranked in ascending order based on their annual energy values. Load duration curves illustrating this ranking can be seen in Figure 4. The forecast in the 50th percentile is the "Median Peak" (the green curve shown). It is scaled so that its maximum matches the peak demand forecast.

Figure 3 | Summary of the Hourly Forecasting Methodology for IRRPs

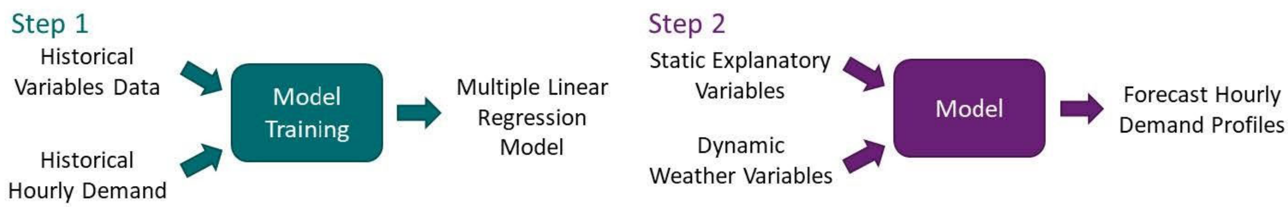
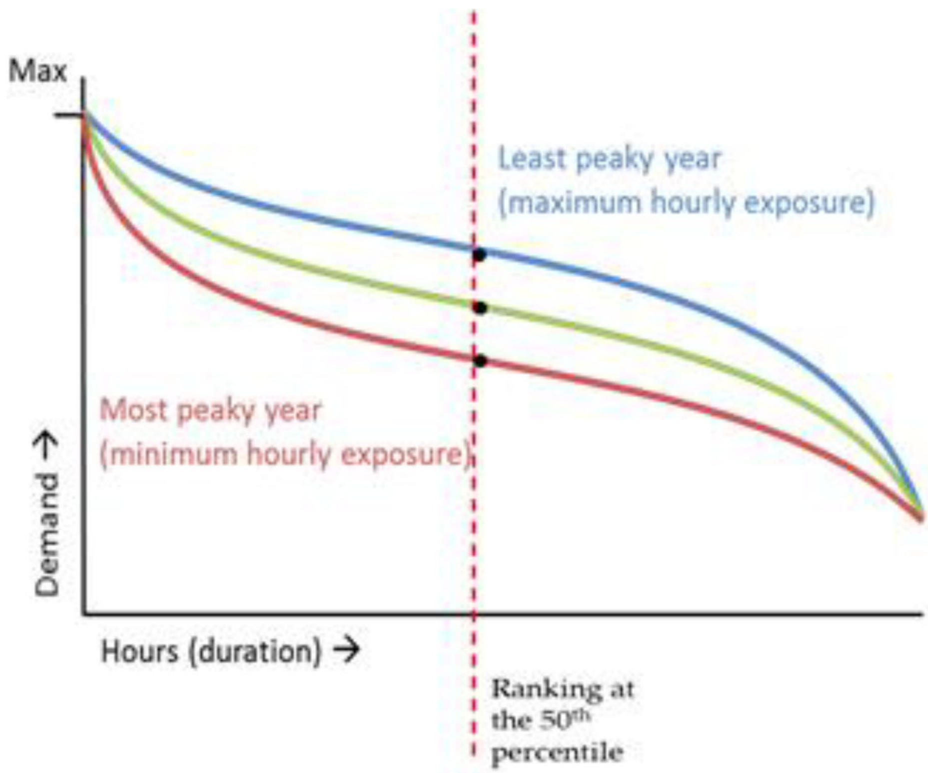


Figure 4 | Illustrative Example: Ranking Hourly Load Profiles by Energy



For this IRRP, LDC hourly load profiles were also an input into the IRRP hourly load forecasts. In the case where an LDC had their own internal set of hourly load profiles that accounted for electrification for a group of stations, those profiles were extended and interpolated so that they covered the entire forecast horizon and then scaled to the forecast peak. The total annual energy of the LDC forecasts was compared to the total annual energy from the traditional linear regression model outputs to ensure that they were similar.

Hourly forecasts are a direct input for further NWA 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 over the 20-year planning horizon.

D.2 Subsystem Capacity Need

Figure 5 and Figure 6 show the monthly and hourly heat maps produced for the Manby West autotransformer need, to illustrate some of the capacity need characteristics in 2035 (mid-term) and 2044 (long-term), respectively. This analysis was performed for each of the identified needs and the hourly profiles were made available on the IESO website. In this illustrative example, each cell in the heat map indicates the expected frequency (i.e., the percentage of time) of a capacity need (e.g., demand levels exceeding a station's load meeting capability) according to the month or hour.

To read the heat maps, it is estimated that loading on the Manby West autotransformers exceeds their load meeting capability by 13 MW for roughly 4% of total hours in July 2035 (Figure 5) and 23% of total hours in July 2044 (Figure 6). By 2035, load levels are estimated to exceed the load meeting capability during the peak summer and winter months (maximum 7%) with the need increasing through to 2044.

Figure 5 | Monthly Heat Map of Manby West Autotransformer Need Magnitudes in 2035

117	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
104	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
91	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
78	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
65	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
52	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
39	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
26	0%	0%	0%	0%	0%	0%	2%	1%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	0%	4%	2%	0%	0%	0%	0%
0	1%	4%	1%	0%	0%	2%	7%	5%	0%	0%	0%	1%
MNTH	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**

Figure 6 | Monthly Heat Map of Manby West Autotransformer Need Magnitudes in 2044

117	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
104	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%
91	0%	0%	0%	0%	0%	0%	1%	0%	2%	0%	0%	0%
78	0%	2%	0%	0%	0%	0%	1%	1%	2%	0%	0%	0%
65	1%	4%	0%	0%	0%	0%	1%	1%	2%	0%	0%	0%
52	8%	10%	2%	1%	1%	1%	4%	3%	3%	0%	1%	1%
39	20%	18%	7%	2%	1%	3%	12%	6%	4%	0%	10%	10%
26	26%	27%	18%	4%	1%	5%	18%	15%	6%	0%	16%	19%
13	32%	33%	28%	12%	1%	10%	23%	20%	9%	0%	24%	25%
0	37%	40%	33%	21%	2%	13%	30%	25%	13%	0%	30%	30%
MNTH	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**

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. Targeting 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 targeting 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 modeling 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 by 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.

Recognizing some of the particular characteristics of the Toronto planning region (e.g., significant role of electrification in forecasted demand growth, multiple demand forecast scenarios, strong municipal and broader stakeholder support for customer-sited energy solutions, etc.) the IESO decided to undertake a new Toronto-region specific Local Achievable Potential Study to inform the

Toronto IRRP, rather than rely on scaled results from the 2022 APS. More information about the Local Achievable Potential Study (LAPS) is presented in Section E.2 below.

E.2 Local Achievable Potential Study

To further enhance and supplement the standard consideration of eDSM in regional planning work underway for the City of Toronto, the IESO engaged consultant ICF International to lead a Local Achievable Potential Study (LAPS) to identify potential for behind-the-meter distributed energy resources (DERs), demand response, and energy efficiency programs. The study identified electricity energy savings potential, peak demand savings potential and associated costs attainable through energy efficiency, demand response, and behind-the-meter DERs over a 20-year period of 2025 to 2045. The LAPS study results can be found at the IESO website.

The APS leveraged load forecasts that are aligned with the Toronto IRRP's reference and high forecast scenarios. For each scenario, the study used a bottom-up approach to determine the energy savings potential from a technical, economic and achievable perspective:

- **Technical Potential** is the savings resulting from the immediate implementation of all technically feasible measures.
- **Economic Potential** is the savings resulting from the immediate implementation of all technically feasible measures that pass the cost-effectiveness test (Program Administrator Cost or PAC test).
- **Achievable Potential** is the savings that can cost-effectively and realistically be acquired once considered adoption dynamics and real-world barriers.

These savings are simulated at the building level (using a digital twin of residential and commercial and institutional building stock) and aggregated to the station level for each scenario. Measures in scope included:

- Behind the Meter DER including battery storage, solar and thermal storage
- Energy Efficiency measures including heat pumps, HVAC, lighting, appliances, and weatherization,
- Demand Response including EV charging, HVAC equipment, and water heaters

The final LAPS includes a presentation of technical, economic and achievable savings, and the associated costs over the 20-year period for both the reference and high electrification forecasts at the station level, and detailed description of the methods, data sources, input assumptions, and data tables.

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 flows is expressed in 2024 CAD.
- The USD/CAD exchange rate was assumed to be 0.70 for the study period.
- 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 45 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; $30-50M/DESN for new 27.6 kV substation (duel-element spot network or DESN design), and $60M per dynamic voltage support device (SVC, STATCOM, condenser). This was informed by cost estimates in Leave-to-Construct application evidence on file with the Ontario Energy Board, benchmark transmission costs, as well as the input received from Hydro One and Toronto Hydro. A range of up to -50% to +100% contingency was assumed for the purpose of this analysis.
- Specific costs from specific projects were also provided by Hydro One or Toronto Hydro and are summarized below
    - Downsview TS: $140 million for one DESN (source: EB-2023-0195, exhibit 2B, section E7.4, page 33 of 55)
    - Downsview SS and TS Total: $170 million (source: EB-2023-0195, exhibit 2B, Downsview TS business case)
    - Scarboro TS expansion: $56.3 million (source: EB-2023-0195, exhibit 2B, section E7.4, page 38 of 55)

- Leaside TS expansion + new double circuit between Cherrywood and Leaside: $800-900 million (source: Hydro One[1])
- Trafalgar to Oakville 230k V double circuit: $150 million (source: Hydro One[1])

F.3 Resource Assumptions

- Overnight capital costs and operating costs for wind, solar and BESS are based on the 2024 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) Workbook publication, 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 99.5% 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.

[1] Cost estimates are prepared for the purpose of the IRRP based on conceptual planning and preliminary information available at this time. No engineering, environmental assessment, real estate, or field review work was completed as part of the development of these estimates and as such these cost estimates provide no cost guarantee or accuracy range.

Appendix G – Planning Study Report

G.1 Description of Study Area

The Toronto electricity planning region roughly encompasses the area within the municipal boundary of the City of Toronto, with some exceptions described below. The region is supplied by three 230 kV corridors:

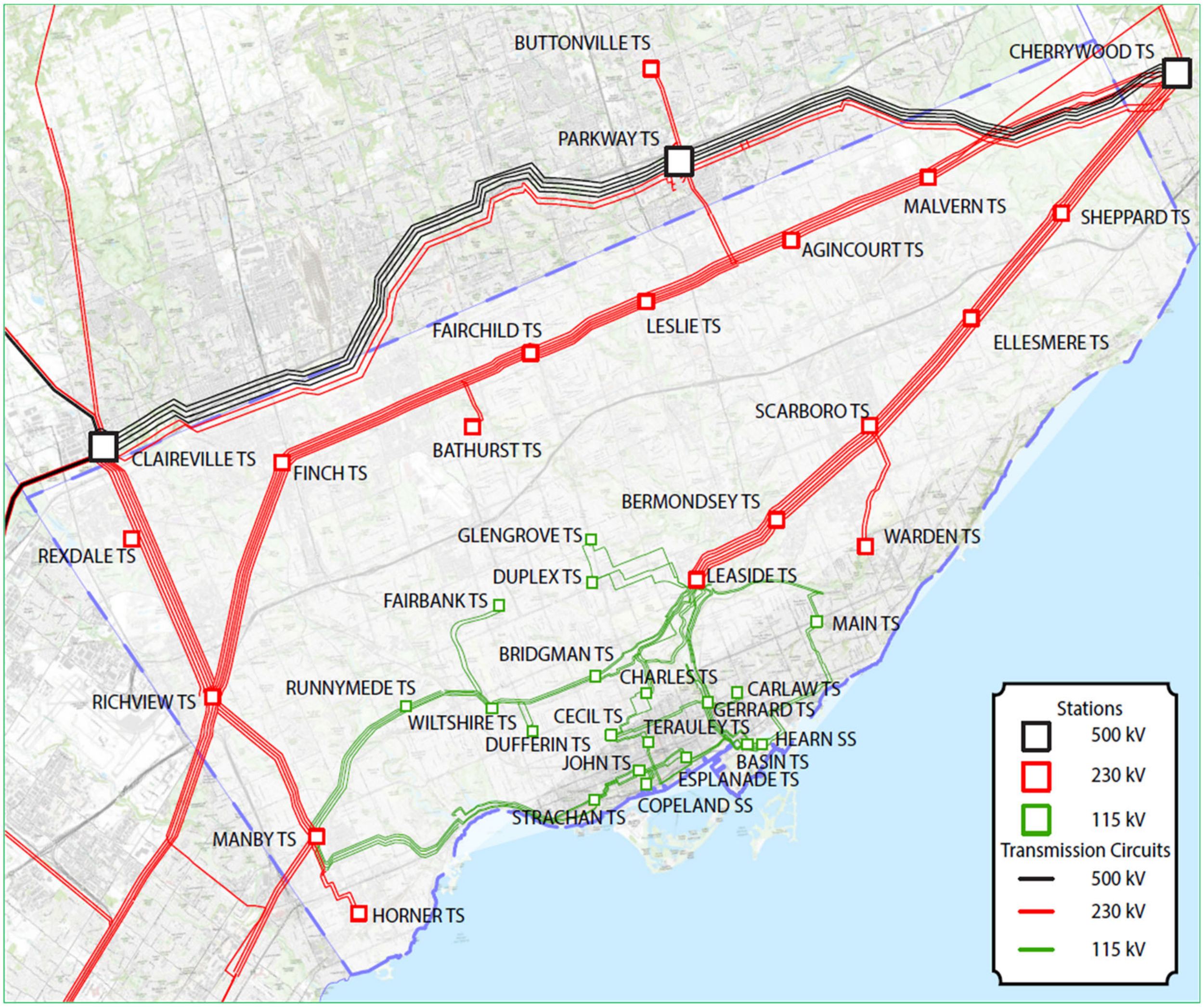
- In the east end by a corridor running from Cherrywood TS (Pickering) to Leaside TS.
- In the west end by a corridor running from Richview TS to Manby TS.
- In the north end by a corridor running from Richview TS to Cherrywood TS / Parkway TS (Markham)

Each of these corridors supplies a number of step down stations as well transfer power to the downtown core via 230/115 kV autotransformer stations at Leaside TS and Manby TS. A mix of overhead and underground 115 kV circuits connecting the aforementioned autotransformer stations to various stepdown load stations supplies the central core of the City of Toronto. The transmission network in the Toronto planning region also includes Portlands Energy Centre (PEC), a natural gas-fired combined cycle power plant located near the Eastern waterfront, connected to the Hearn Switching Station (SS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering. Figure 7 provides a geographical overview of the boundaries of the Toronto Planning Region and the transmission infrastructure located within it.

Numerous distributed energy resource (DER) facilities are located throughout the city. For example, through previous procurements such as the Feed-in Tariff (FIT) program, Renewable Energy Standard Offer Program, and Combined Heat and Power Standard Offer Program (CHPSOP), approximately 1,900 individual renewable and CHP facilities have been placed in service in the City of Toronto. In addition to those procurements, Toronto Hydro provided a breakdown of current DERs connected through their net metering program and a forecast of expected DER connections up to 2029. At the time the IRRP forecast was produced, there were approximately 300 MW of DERs connected within the City of Toronto.

For the purpose of assessing the loading on the circuits between Richview TS and ManbyTS / Cooksville TS, additional load in southern Mississauga and Oakville (specifically the Cooksville, Lorne Park, Ford Oakville and Oakville TS's) was also considered. These loads are not part of the Toronto planning region as defined by the OEB regional planning process (they are part of the GTA West region), but as they contribute to loading on this corridor, data from the most recent GTA West IRRP forecast for these stations was included.

Figure 7 | Map of the Toronto Planning Region



The technical study was broken down into the following sub-regions for the purposes of reporting:

Richview x Claireville x Manby

The Richview/Claireville x Manby 230kV area supplies load in the western Toronto neighbourhoods and includes the following assets:

- 230 kV circuits, R1K, R2K, R13K, R15K, V72R, V73R, V74R, V76R, V77R, and V79R
- 230 kV circuits K23C, K24C, and R24C
- The following DESNs: Richview TS, Rexdale TS, and Manby TS
- The following transmission connected capacitors: Richview SC21, Richview SC22, Manby SC21, and Manby SC22.

Note the Manby autotransformers are included in the Manby East and Manby West areas.

The area is considered part of the bulk power system (BPS) as defined by NPCC Directory 1 and therefore more stringent planning criteria, including consideration of N-1-2 planning events applies.

The status of Portlands Energy Center does not have any effect on the Manby West area except for the ability to transfer load out of the area to the Leaside 115kV area to provide post-contingency relief.

The Cooksville TS DESN is fed radially from Manby via K23C, K24C, and R24C and is not part of the study area and therefore needs for this station were not included in the study.

Lorne Park TS, Ford Oakville TS, and Oakville TS DESNs are fed radially from Cooksville via B15C and B16C and are not part of the study area and therefore needs for this station were not included in the study.

Manby East

The Manby East area supplies load in the northern Etobicoke and downtown Toronto neighbourhoods and includes the following assets:

- The auto transformers in the Manby East yard
- 115kV circuits, K1W, K3W, K11W, K12W
- The following DESNs: Fairbank TS, Runnymede TS, and Wiltshire TS

The area is considered non-BPS as per NPCC Directory 1 and therefore N-1-2 planning events do not apply. The status of PEC does not have any effect on the Manby East area except for the ability to transfer load out of the area to the Leaside 115kV area post contingency.

Manby West

The Manby West area supplies load in the southern Etobicoke and downtown Toronto neighbourhoods and includes the following assets:

- The auto transformers in the Manby West yard
- 115kV circuits, K6J, K13J, K14J, D11J, D12J
- 115kV circuits H2JK, (between Manby and John TS)
- The following DESNs: Copeland MTS, John TS, and Strachan TS

The area is considered non-BPS as defined by NPCC Directory 1 and therefore N-1-2 planning events were not required to be assessed. The status of PEC does not have any effect on the Manby East area except for the ability to transfer load out of the area to the Leaside 115kV area post contingency.

Leaside x Wiltshire

The Leaside x Wiltshire area supplies load in the midtown neighbourhoods west of Yonge and includes the following assets:

- 115kV circuits, L13W, L14W, L15, L18W
- The following DESNs: Dufferin TS and Bridgman TS

The area is considered non-BPS as defined by NPCC Directory 1 and therefore N-1-2 planning events were not required to be assessed. The status of PEC does not have any effect on the Leaside x

Wiltshire area as this area is supplied radially from Leaside on circuits to which Portlands is not interconnected.

Duplex / Glengrove

The Leaside x Duplex / Glengrove area supplies load in midtown neighbourhoods near Yonge and St. Clair and includes the following assets:

- 115kV circuits D6Y, L2Y, L5D, L16D
- The following DESNs: Duplex TS and Glengrove TS

The area is considered non-BPS as defined by NPCC Directory 1 and therefore N-1-2 planning events were not required to be assessed. The status of PEC does not have any effect on the Leaside x Duplex / Glengrove area as this area is supplied radially from Leaside on circuits to which Portlands is not interconnected.

Leaside x Main/Basin

The Leaside x Main / Basin area supplies load in the downtown neighbourhoods including the Danforth east south to the Port Lands and includes the following assets:

- 115kV circuits H1L, H3L, H7L, H11L
- The following DESNs: Basin TS, Carlaw TS, Gerrard TS, and Main TS

The area is considered non-BPS as defined by NPCC Directory 1 and therefore N-1-2 planning events were not required to be assessed. The status of the Portlands Energy Center does affect the Leaside x Main / Basin area as when PEC is in service, load on the indicated circuits is supplied from both Hearn SS and Leaside TS as compared to only from Leaside TS when PEC is out of service.

Leaside x Charles/Cecil/Esplanade/Terauley

The Leaside x Main / Basin area supplies load in the downtown neighbourhoods and includes the following assets:

- 115kV circuits C5E, C7E, H9DE, H10DE, H6LC, H8LC, L4C, L9C, and L12C
- The following DESNs: Cecil TS, Charles TS, Esplanade TS, and Terauley TS

The area is considered non-BPS as defined by NPCC Directory 1 and therefore N-1-2 planning events were not required to be assessed. The status of the Portlands Energy Center does affect the Leaside x Charles/Cecil/ Esplanade/Terauley area as when PEC is in service load on the indicated circuits is supplied from both Hearn SS and Leaside TS as compared to only from Leaside TS when PEC is out of service.

Cherrywood x Leaside

The Cherrywood x Leaside 230kV area supplies load in the Eastern Toronto and Scarborough neighbourhoods and includes the following assets:

- 230 kV circuits, C2L, C3L, C14L, C15L, C16L, and C17L

- The following DESNs: Bermondsey TS, Ellsemere TS, Scarborough TS, Sheppard TS, Warden TS, and Leaside TS
- The following autotransformers at Leaside TS: T11, T12, T14, T15, T16, T17
- The following transmission connected capacitors: Leaside SC11, Leaside SC12, Leaside SC14, and Leaside SC15

The area is considered BPS as defined by NPCC Directory 1 and therefore more stringent planning criteria, including consideration of N-1-2 planning events applies. The status of PEC has a direct impact on the loading of circuits and autotransformers in this area.

Richview x Cherrywood/Parkway

The Richview x Cherrywood / Richview x Parkway 230 kV area supplies load in the West Toronto neighbourhoods and includes the following assets:

- 230 kV circuits, C4R, C5R, C18R, C20R, P21R, P22R, and C10A
- The following DESNs: Agincourt TS, Bathurst TS, Cavanagh TS, Fairchild TS, Finch TS, Leslie TS, and Malvern TS
- The following new wholesale load stations Islington TS

The area is considered BPS as defined by NPCC Directory 1 and therefore more stringent planning criteria, including consideration of N-1-2 planning events applies. The status of PEC does not have a material impact on the Richview x Cherrywood / Richview x Parkway 230 kV Manby West area.

G.2 Scenarios Assessed and Criteria

Three scenarios were assessed as shown in Table 3. The status of PEC is critical for the reliable operation of the portion of the IESO controlled grid within the city of Toronto and as such second scenario identifies the incremental needs that would arise as a result of a PEC out-of-service scenario without a direct replacement resource. The third scenario reflects higher rates of electrification as identified in the load forecast methodology and the incremental needs that would result. This scenario assumed that a new supply in the order of 1000 MW[2] is located at Hearn SS as previous assessments indicated the existing supply into Hearn SS is insufficient to meet reliability requirements under higher electrification assumptions.

Table 3 | Summary of Scenarios Assessed

Forecast	Status of Portlands Energy Center	Season
Reference Forecast	Continues to operate	Summer /Winter
Reference Forecast	Retired	Summer /Winter
High Electrification Forecast	Assumed a Third Supply of 1000 MW at Hearn SS	Summer /Winter

[2] The 1000MW supply was modeled as both an AC supply and HVDC.

Table 4 summarizes the application of weather dependency demand forecast and contingency type applied to each planning scenarios evaluated for the various sub areas within the Toronto IRRP.

- N-1, N-1-1, and N-2[3] events under extreme weather demand conditions were evaluated.
- As per section 2.6 of ORTAC, "(w)here reliability depends on local generation, sensitivity studies should be done to assess the impact of outages of local generation" and thus N-G-1 and N-G-2 events were evaluated with unit G1,3 at PEC assumed out-of-service, under normal weather demand conditions. Only subareas impacted by PEC unit status were evaluated.
- N-1-2 scenarios were only evaluated on areas designated as part of the Bulk Power System (BPS) under normal weather demand conditions.

Table 4 | Weather Demand and Contingencies Assessed for Each Sub Area

Area	Extreme Weather			Normal Weather		
	N-1	N-2	N-1-1	N-G-1	N-G-2	N-1-2
Richview x Manby	✓	✓	✓	✓	✓	✓
Manby West	✓	✓	✓	×	×	×
Manby East	✓	✓	✓	×	×	×
Leaside x Wiltshire	✓	✓	✓	×	×	×
Leaside x Duplex/Glengrove	✓	✓	✓	×	×	×
Leaside x Main/Basin	✓	✓	✓	✓	✓	×
Leaside x Charles/Cecil/Esplanade/Terauley	✓	✓	✓	✓	✓	×
Cherrywood x Leaside	✓	✓	✓	✓	✓	✓
Richview x Cherrywood/Parkway	✓	✓	✓	✓	✓	✓

*The Largest Generator out-of-service is the PEC steam turbine which also removes one gas turbine.

Criteria

The study adhered to the planning criteria in accordance with events and performance as detailed by:

- North American Electric Reliability Corporation TPL-001 "Transmission System Planning Performance Requirements;"

[3] ORTAC does not require N-2 events for non-BES (i.e., local areas); however, they were evaluated due to the social economic importance of the area and to determine incremental discretionary need that may arise. It is important to note that the post contingency topology of N-1-1 and N-2 events are similar in many cases as such the needs reflected from N-2 events would also be present for N-1-1 events in lieu of control actions between contingencies.

- Northeast Power Coordinating Council Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System;" and
- IESO "Ontario Resource and Transmission Assessment Criteria."

Table 5 shows the types of contingencies assessed and how they map to applicable reliability standards and criteria. The table also specifies the thermal loading criteria and amount of load rejection/curtailment permitted by ORTAC.

Table 5 | Mapping of Planning Scenarios to NERC / NPCC Standards and ORTAC Criteria.

Pre-Contingency	Contingency[4]	Type	Mapping to TPL/D1 Event	Rating[5]	Maximum Allowable Load Loss
All elements in-service	None	N-0	P0	Continuous	None
	Single	N-1	P1, P2	LTE	150 MW by configuration
	Double	N-2	P7, P4, P5	STE, reduced to LTE	150 MW by curtailment/ rejection; 600 MW total
All transmission elements in-service, local generation out-of-service, followed by system adjustments (satisfy ORTAC 2.6 Re: local generation outage) Single	None	N-G-0	N/A	Continuous	None
	Single	N-G-1	P3	LTE	150 MW by configuration; >0 MW by curtailment / rejection;[6] 600 MW total
	Double	N-G-2	N/A	STE, reduced to LTE	>150 MW by curtailment / rejection;[7] 600 MW total

[4] Single contingency refers to a single zone of protection: a circuit, transformer, or generator. Double contingency refers to two zones of protection; the simultaneous outage of two adjacent circuits on a multi-circuit line, or breaker failure.

[5] LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.
STE: Short-term emergency rating. 15-min rating for circuits and transformers.

[6] Only to account for the magnitude of the generation outages.

[7] Only to account for the magnitude of the generation outages.

Pre-Contingency	Contingency[4]	Type	Mapping to TPL/D1 Event	Rating[5]	Maximum Allowable Load Loss
Transmission element out-of-service, followed by system adjustments Double	Single	N-1-1	P6	STE, reduced to LTE	150 MW by curtailment / rejection; 600 MW total
	Double	N-1-2	Cat II	STE, reduced to LTE	N/A

In addition to thermal criteria pre- and post-contingency minimum and maximum voltages and voltage change criteria must be adhered to for all scenarios as per Table 6.

Table 6 | Post-Contingency Voltage Requirements

Applicable Limit	Nominal Bus Voltage (kV)		
	500	230	115
Post-contingency Maximum Voltage	550	250	127
Post-contingency Minimum Voltage	470	207	108
Post-contingency Maximum deviation	10%	10%	10%

The system must be shown to be stable if the most critical parameter is increased by 10% under the following conditions:

- 10% margin on pre-contingency voltage collapse.
- 10% margin on post-contingency voltage collapse.
- 10% margin on transient instability.

Once load is lost either by configuration or by actions such as planned load rejection via a pre-defined Remedial Action Scheme or manual load rejection following a contingency to reduce loading to the LTE ratings, load must be restored in accordance with the following:

- Any load lost must be restored in under 8 hours.
- Any amount of load lost in excess of 150 MW must be restored in 4 hours.
- Any amount of load lost in excess of 250 MW must be restored in 30 minutes.

Major Interface Flows

A major interface flow that feeds into the Toronto Region is FETT (Flow East Towards Toronto). The Toronto IRRP study respected the limits of FETT but studies of the capability of the FETT interface were out of scope of this IRRP.

Monitored Circuits and Sections

All pre- and post-contingency flows on 115kV and 230kV circuit sections were monitored and compared against reported equipment continuous ratings, long-term emergency ratings (LTE), and short-term emergency ratings (STE) as reported by the asset owner consistent with NERC FAC-008. The ability of the 500 kV system to supply the Greater Toronto Area (GTA) was outside the scope of this study and therefore the performance of the 500 kV system was not monitored.

Monitored Autotransformers

All pre- and post-contingency flows on 230/115 kV autotransformers were monitored and compared against reported equipment continuous, LTE, and STE ratings as reported by the asset owner consistent with NERC FAC-008. The ability of the 500/230 kV autotransformers to supply the GTA was outside the scope of this study and therefore 500/230 kV autotransformers were not monitored.

Contingencies

All contingencies were defined as one of the following consistent NERC TPL-001, NPCC D1, and IESOs ORTAC standards:

Single Element Contingencies:

- A permanent three-phase fault on any generator, transmission circuit, transformer, shunt or bus section with normal fault clearing.
- Loss of any element without a fault.

Double Element Contingencies

- Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent circuits of a multiple circuit tower, with normal fault clearing.[8]
- A permanent phase-to-ground fault on any transmission circuit, transformer or bus section with delayed fault clearing.

G.3 System Assumptions

Load Forecast

The needs identification study used net peak summer forecast snapshots in 2025, 2028, 2032, 2035, 2039, and 2044 (end of study period). The final published peak demand forecasts, by station, are available on the IESO website.

Local Generation Assumptions

Only registered Market Participant facilities were explicitly represented in the IESO's power system analysis models. Local generation includes PEC. PEC is located near the Eastern waterfront and is connected to the Hearn Switching Station (SS) shown in Figure 7. It consists of two combustion

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[8] If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, this condition can be excluded, or if they share a common structure for 1.62 km of less this condition can be excluded.

turbine-generators (“CTG”, G1 and G2) and heat recovery steam generators supplying a single steam turbine-generator (“STG”, G3). PEC uses Lake Ontario as its ultimate heat sink.

If the STG is unavailable, the capability of PEC is limited by environmental constraints. Depending on ambient conditions, output from both CTGs may not be possible, and therefore cannot be firmly relied on for planning purposes. Therefore, for planning purposes, the maximum firm output from a single CTG of 175/197 MW is assumed when the STG is out of service during summer conditions (Table 7).

Table 7 | PEC Generation Seasonal Output Assumptions

Generating Station	Summer (MW)	Winter (MW)
CTG1	175	197
CTG2	175	197
STG3	225	230
Total	575	624

DERs, which include contracted FIT and other projects connected to the distribution system, were assumed to be a load modifier and their output was reflected as a net reduction in load. Distributed generation capacity assumptions were based on winter and summer peak contribution factors for winter and summer cases respectively, consistent with the assumptions used for the IESO’s Reliability Outlook.

Normal Supply and Load Transfers

The Toronto system operates with the Richview 230 kV, Claireville 230 kV, and Leaside 115 kV buses operated electrically split to prevent fault levels exceeding breaker interrupting capability. Similarly, the Manby East and Manby West 115 kV systems are operated split from the Leaside 115 kV system via normally open points at Wiltshire TS and Copeland MTS. There are also normally open points at Bridgeman TS and Duplex TS to prevent paralleling the Leaside 115kV buses via these stations. The protections and equipment do allow for transferring load between supplies but do not allow for parallel operation.

For the purpose of the study, all load was assumed to be supplied from normal operating configuration unless otherwise stated.

Planned Upgrades

Several upgrades / asset replacements have been identified in previous IRRP planning cycles. Only those projects that have submitted technical characteristics via the IESOs System Impact Assessment process were reflected in the technical study. Planned upgrades and asset replacement projects without new technical characteristics were assessed with the existing parameters.
Table 8 provides a summary of new transmission facilities reflected in the planning assumptions.

Table 8 | New Transmission Facilities Considered (Excluding DESN Transformer Replacements)

Project	Description	Assumed In-Service Date
Richview to Manby Transmission Reinforcement "Etobicoke Greenway"	Rebuilding an idle 115 kV double-circuit line on the Richview to Manby transmission corridor to a 230 kV standard and operating it at 230 kV	April 2026 for Phase 1 Beyond 2031 for Phase 2[9]
C5E/C7E Underground Cable	Underground cable replacements	December 2026
H2JK, H9DE, H10DE Conductor Replacement	Replace conductors between Don Fleet Jct. to Esplanade	December 2024
Copeland TS Stage 2[10]	Addition of two new transformers (T2 and T4)	2026

Remedial Action Schemes

There are two existing Remedial Action Schemes (RASs) in the region. These are The Hearn SPS – PEC Generation Rejection Scheme (RAS 205) and the Manby TS 230/115 kV Autotransformer Overload Protection Scheme (RAS 230). Both RASs are currently classified as a "Limited Impact RAS" as per NPCC directory 7 and NERC PRC-012.

Hearn SPS – Portland Energy Centre Generation Rejection Scheme

This RAS addresses post-contingency overloading of 115kV circuits out of Hearn SS. Generating units at PEC can be selected for rejection or runback for pre-defined contingencies which result in the loss of one or more 115kV circuits emanating from Hearn SS. The RAS will send trip / runback signals to the generating unit(s) when the contingency for which the unit(s) were armed is detected and upon receipt the output of the facility will be reduced, thus reducing the loading the remaining 115 kV circuits. As per ORTAC there is no restriction on the use of this RAS.

Manby TS 230/115 kV Autotransformer Overload Protection Scheme

This RAS addresses post-contingency autotransformer overloading at Manby East and Manby West. Load at feeders supplied by downstream DESN stations can be armed to trip for pre-defined contingencies which result in the loss of one or more autotransformer. The RAS will send trip signals to the downstream DESN station(s) when the contingency for which the load is armed is detected and upon receipt feeder breakers will open, thus reducing the loading the remaining Manby auto-transformers. As per ORTAC a maximum of 150 MW can be armed for any contingency associated with this RAS as there is no downstream generation.

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[9] Phase 1 refers to rebuilding of existing idle 115 kV double circuit to 230 kV double circuit standard, and supercircuiting of circuits R2K and R15K. Phase 2 refers to the unbundling of the supercircuits such that there will be six 230 kV circuits in the corridor between Manby TS and Richview TS. Refer to the SIA Report 2018-637 for more details.

[10] Additional load in the Copeland TS Stage 2 SIA will be reflected in the IRRP forecast.

G.4 Transmission System Needs

Table 9 and Table 10 provide the expected date for each transmission need for the reference forecast scenario as well as the accelerated need dates should alternative scenarios including PEC retirement/ out-of-service and high electrification demand growth materialize. In certain cases, the needs are only present under a PEC retirement and/or high electrification demand forecast and therefore are not present in the reference forecast.

Note that ORTAC allows elements to be operated to the STE rating for N-1-1 and N-2 events provided there are mechanisms available to system operators to reduce the loading to the LTE rating within 15 minutes. These operations can include manually shedding load post-contingency up to the limits as summarized in Table 5. This requirement was satisfied for all planning events unless otherwise specified.

Table 9 | Summary of Needs Summer

Need	Year – Ref. Forecast	LMC (MW)	Year - PEC Retirement	LMC (MW)	Year - High Elec. Forecast	LMC (MW)
Richview TS x Manby TS Post Phase 2	2032	1840	-	-	2030	1840
Manby East Autotransformers[11]	2044	500	-	-	2035	500
K1W/K3W St. Clair Jct. x Fairbank TS	2036	179	-	-	2031	179
K1W and K3W Manby TS x St. Clair Jct.	-	-	-	-	2044	350
Manby West Autotransformers[12]	2028	488	-	-	2028	488
K13J/K14J Manby TS x Riverside Jct.	2026	435	-	-	2026	435
K13J/K14J Strachan Jct. x Strachan Jct.	2032	510	-	-	2030	510
H2JK/K6J Manby TS x Riverside Jct.	2029	493	-	-	2028	493

[11] The need may be earlier depending on the ratings for the scheduled replacement of T7 and T9
[12] The need may be earlier depending on the ratings for the scheduled replacement of T12

Need	Year – Ref. Forecast	LMC (MW)	Year - PEC Retirement	LMC (MW)	Year - High Elec. Forecast	LMC (MW)
Manby West Post Contingency Voltage Support	2035	525	-	-	2030	525
L13W and L18W Bridgman x Barlet / Dufferin JCT.	2039	157	-	-	2034	157
L18W Leaside TS to Bridgman TS	-	-	-	-	2039	350
L15 Leaside TS x Bridgman TS	-	-	-	-	2036	159
L14W Birch JCT x Bridgman TS	-	-	-	-	2042	178
H1L/H3L Leaside TS x Bloor St.	2036	310[13]	<2025	210	-	-
H1L/H3L Hearn SS x Basin TS	2041	385	-	-	2037	370
C2L + C3L Double Ctg.	<2025	<1150	<2025	<1150	<2025	<1150
Leaside Area Voltage Support	2038[14]	2610	<2025[15]	2170	2034	2610
Leaside Auto Transformers	Limited by Voltage Issues	-	<2025[16]	1000	Limited by Voltage Issues	-
Cherrywood x Leaside 230kV Circuits	Limited by Voltage Issues	-	Limited by Voltage Issues	-	Limited by Voltage Issues	-
P22R/C18R Bathurst Jct. x Bathurst TS	2038	417	-	-	2037	417

13 The need is driven by normal weather and is also influenced by the loading in the loading in the Leaside/Charles/Cecil/Esplanade/Terauley area

14 The need is driven by N-G-2 events during normal weather

15 The need is driven by N-2 event during extreme weather

16 The need is driven by N-1-2 events during normal weather

Table 10 | Summary of Needs Winter

Need	Year – Ref. Forecast	LMC (MW)	Year - PEC Retirem ent	LMC (MW)	Year - High Elec. Forecast	LMC (MW)
Richview TS x Manby TS Post Phase 2	2032	1856	-	-	2028	1856
Manby East Auto Transformers	2044	555	-	-	2034	555
K1W/K3W St. Clair Jct. x Fairbank TS	2039	200	-	-	2032	200
K1W and K3W Manby TS x St. Clair Jct.	-	-	-	-	2036	370
K11W and K12W Manby TS x Runnymede TS	-	-	-	-	2039	650
Manby West Autotransformers[17]	2032	500	-	-	2028	500
K13J/K14J Manby TS x Riverside Jct.	2027	450	-	-	2027	450
K13J/K14J Strachan Jct. x Strachan Jct.	2039	545	-	-	2031	545
H2JK/K6J Manby TS x Riverside Jct.	2036	519	-	-	2030	519
Manby West Post Contingency Voltage Support	2039	545	-	-	2031	545
L13W and L18W Bridgman x Barlet / Dufferin JCT.	2036	180	-	-	2029	180
L18W Leaside TS to Bridgman TS	2041	370	-	-	2033	370

[17] The need may be earlier depending on the ratings for the scheduled replacement of T12

Need	Year – Ref. Forecast	LMC (MW)	Year - PEC Retirem ent	LMC (MW)	Year - High Elec. Forecast	LMC (MW)
L15W Leaside TS x Bridgman TS	2036	145	-	-	2026	145
L14W Birch JCT x Bridgman TS	-	-	-	-	2037	190
L5D Leaside TS x Duplex TS	-	-	-	-	2038	270
H1L/H3L Leaside TS x Bloor St.	2038	380[18]	<2025	<260	-	-
H1L/H3L Hearn SS x Basin TS	2042	455	-	-	2036	420
C2L + C3L Double Ctg.	<2025	<1250	<2025	<1250	<2025	<1250
Leaside Area Voltage Support	2034[19]	2510	<2025[20]	2170	2031	2510
Leaside Auto Transformers	Limited by Voltage Issues	-	<2025[21]	1050	Limited by Voltage Issues	-
Cherrywood x Leaside 230kV Circuits	Limited by Voltage Issues	-	Limited by Voltage Issues	-	Limited by Voltage Issues	-
P22R/C18R Bathurst Jct. x Bathurst TS	2044	468	-	-	2044	468

[18] The need is driven by normal weather and is also influenced by the loading in the loading in the Leaside/Charles/Cecil/ Esplanade/Terauley area.
[19] The need is driven by N-G-2 events during normal weather.
[20] The need is driven by N-2 events during extreme weather.
[21] The need is driven by N-1-2 events during normal weather.