Toronto Integrated Regional Resource Plan

October 31, 2025

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List of Acronyms

DESN	Dual-Element Spot Network
DG	Distributed Generation
DLT	Distribution-level Load Transfers
DR	Demand Response
DS	Distribution Station
DVS	Dynamic Voltage Support
eDSM	Electricity Demand Side Management
ESS	Energy Storage System
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
NPV	Net-present value
MTS	Municipal Transformer Station
MVA	Megavolt ampere
Mvar	Megavolt ampere reactive
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portlands Energy Centre
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transformer Station
TWG	Technical Working Group

Executive Summary

This Integrated Regional Resource Plan (IRRP) addresses electricity needs in the Toronto Region over a 20-year period, to 2044. The Toronto Region is defined by electrical infrastructure boundaries and the municipal boundaries of the City of Toronto.

For the purposes of this IRRP, the Toronto Region has been divided into three electrical subsystems: Northern, Western, and Eastern Toronto. These subsystems reflect the configuration of the transmission system and the location of major step-down transformer stations and other points of system supply. The IRRP focuses on identifying and addressing electricity needs in each of these subsystems, while also coordinating with broader bulk system planning.

The IRRP considers the reliability impacts of the significant demand growth forecast for the Toronto Region. Peak demand is expected to nearly double by 2043 and while the region has historically been summer-peaking, the region could become winter peaking by the early-2030s. The plan considered reference and high electrification forecast scenarios to determine the needs of the region, identify potential investments to address those needs, and offer corresponding recommendations to ensure the system remains reliable and resilient to demand growth uncertainties in the long term.

To identify near, medium, and long-term needs, the Technical Working Group[1] assessed station capacity, supply capacity, reliability, and load security needs across the region. A combination of wires and non-wires solutions were evaluated, with a number of recommendations made to address needs as they arise.

Recommendations include immediate actions to develop infrastructure such as new and expanded transmission stations to increase the amount of electricity that can flow into Toronto, and two locations for energy storage facilities to inject electricity when needed and improve reliability.

Given the pace of growth in the City of Toronto, the IESO is also recommending a new underwater transmission line connecting downtown Toronto to Bowmanville via Lake Ontario. While the IESO assessed alternative options including over and underground transmission options, the underwater Third Line is the preferred option. This line can accommodate significantly more growth in Toronto and the GTA, enabling 900 MW of supply to flow from the east; improving supply diversity and resilience by introducing a true third supply path into the downtown core; as well as supporting load restoration following major power disruptions, among other benefits.

Non-wires alternatives (NWAs) such as targeted electricity demand-side management (eDSM) and distributed energy resources (DERs) including solar and storage, are also recommended to help potentially defer long-term infrastructure requirements. The plan recommends an incremental 320 MW of summer and 121 MW of winter savings by 2045, on top of the planned delivery of 847 MW of summer and 756 MW of winter savings through Save on Energy programs. For context, the current peak demand of Toronto is close to 5,000 MW. These local programs will be developed and made available to Toronto residents and businesses as part of the new eDSM Framework. The

[1] The Technical Working Group includes the IESO, the Local Distribution Company, Toronto Hydro Electric-System Limited and the lead transmitter, Hydro One Networks Inc.

Technical Working Group encourages all Toronto residents and businesses to take full advantage of Save on Energy programs to maximize incremental eDSM achieved in the City.

Options for monitoring long-term needs, towards the end of the study period, are also proposed. While they do not yet require action, it is important to preserve the long-term viability of certain solutions.

PEC is currently critical to the reliability of both Toronto's and the broader province's electricity supply. The Third Line is foundational to a future without PEC; however, the line is needed regardless of the future of PEC. Once the line comes into service, local reliance on PEC will be reduced, but it may still be needed to meet the provincial grid's peak needs. The Toronto IRRP is focused on local supply and does not address matters of provincial supply.

The study has also considered points of coordination with ongoing bulk planning initiatives, including the South and Central Bulk Plan, which is studying bulk system needs and potential upgrades with a notional 2035 focus. A second, longer term bulk planning study, expected to be initiated later in 2026 will focus on bulk system needs into the 2040s, including the potential impact of bulk enhancements on regional supply. Both studies have the potential to affect longer term needs and the feasibility of solutions available to/in the area. Specifically, in terms of PEC's contribution to provincial resource adequacy, the Bulk Plan will be looking at the need and timing of bulk transmission upgrades needed for a future where PEC (and other emitting resources in the GTA) may be out-of-service. The current study is expected to be complete in early 2026.

Engagement was a key input to the development of this IRRP. The IESO engaged with municipalities, Indigenous communities, stakeholders, and the public throughout the planning process. Activities included targeted one-on-one discussions with the City of Toronto and Indigenous communities, technical briefings with communities and six public webinars to share information and solicit written feedback. The overarching themes of feedback received during the development of the IRRP primarily focused on the future of PEC; preference for non-wire options; enhanced transparency for data/information and decision rationale; alignment with City of Toronto decarbonization initiatives; recognition of the need for a third supply line; coupled with requests for more information on the evaluation of options, impacts of routing options, and concern it would bring nuclear energy into the City. The feedback received helped shape the demand forecast, identify local priorities, and inform the recommended solutions.

The Technical Working Group will continue to monitor growth, electrification trends, and large customer connections across the region. The group will meet regularly to track progress, assess changing conditions, and update the plan as needed. If underlying assumptions change significantly, the IRRP may be amended, or a new planning cycle initiated ahead of the standard five-year schedule mandated by the Ontario Energy Board.

Summary of Recommendations

Needs identified and resulting recommendations[2] emerging from this plan to enable growth driven by urban and economic development and electrification, consist of:

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[2] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

Table 1 | Northern Toronto Recommendations

Need	Project	Expected In-Service (based on Reference Forecast)
Overall Station Capacity and Supply Capacity	Build Downsview MTS	2033

Table 2 | Western Toronto Recommendations

Need	Project	Expected In-Service (based on Reference Forecast)
Manby TS (West) Autotransformers	Reliance on the Manby Remedial Action Scheme[3]	Ongoing
	Permanent transfer of Copeland MTS T2/T4 to Leaside Supply	2026
	Incremental eDSM	Ongoing
	Develop Energy Storage Systems at or downstream of the Manby West autotransformers	2029/2030
Manby TS (East) Autotransformers	Reliance on the Manby Remedial Action Scheme	Ongoing
	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
	Incremental eDSM	Ongoing
Manby to Riverside Circuits	Increase transmission capacity by upgrading circuits from Manby TS to Riverside TS[4]	2028
St Clair to Fairbank Circuits	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
Fairbank TS	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
Strachan TS	Incremental eDSM	Ongoing
Manby DESN	Monitor station capacity need as need arises towards the end of forecast	Ongoing

[3] A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and MVar), tripping load, or reconfiguring the system.

[4] Note that this was also recommended by the 2022 Needs Assessment Report, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto_Region_Needs_Assessment_Report_Third_Cycle_Regional_Planning.pdf

Table 3 | Eastern Toronto Recommendations

Need	Project	Expected In-Service (based on Reference Forecast)
Leaside to Bridgman to Dufferin Circuits	Increase transmission capacity to Dufferin TS by upgrading underground circuits between Dufferin TS and the Bartlett/Dufferin Junctions	2036
	Transfer Dufferin TS load to upgraded Wiltshire TS	2036
	Develop Energy Storage Systems at or downstream of Dufferin TS	2036
Leaside to Bloor to Hearn Circuits	Increase transmission capacity by upgrading circuits from Leaside TS to Bloor JCT and from Hearn SS to Basin TS	2036
	Incremental eDSM	Ongoing
Scarboro TS, Warden TS, and Sheppard TS	Develop an additional DESN at Scarboro TS to increase capacity	2035
Glengrove TS	Investigate the feasibility of load transfers from Glengrove TS to Duplex TS	2042
Dufferin TS	Develop Energy Storage Systems at or downstream of Dufferin TS	2040
Basin TS	Develop an expansion of Basin TS or add a new station in the area.	2036
Overall Supply Capacity	Develop underwater HVDC transmission supply towards Hearn SS	2034

1 Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Toronto Region (the "Region") over a 20-year period, from 2025 to 2044. The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 1. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations – Leaside Transformer Station (TS) and Manby TS. A small number of distribution feeders from Toronto also supply customers in the neighbouring cities of Mississauga and Pickering.

In addition to the transmission infrastructure, the Portlands Energy Centre (PEC) is a 600-megawatt (MW) capacity natural gas-fired combined cycle power plant that provides a major source of supply to Toronto. This station is located near the Eastern waterfront and is connected to the Hearn Switching Station (SS), south of Basin TS, as shown in Figure 1.

The region is summer peaking and the 2022 weather-corrected peak summertime electricity demand in the Toronto region was approximately 4,600 MW.[5]

The region's electricity is delivered by the local distribution company (LDC) Toronto Hydro-Electric System Limited (Toronto Hydro). Hydro One Networks Inc. (Hydro One) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Technical Working Group, composed of Toronto Hydro, Hydro One, and the IESO.

The IESO also acknowledges that Toronto is the traditional territory of many nations, and is committed to ongoing, meaningful dialogue with Indigenous communities to inform long-term planning in Toronto and across Ontario. To raise awareness about the regional planning cycle in Toronto, and invite participation in the engagement process, the IESO's engagement efforts included outreach to Indigenous communities throughout the development of the plan, including to the Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, Alderville First Nation, Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, Mississaugas of Scugog Island First Nation, and Métis Nation of Ontario.

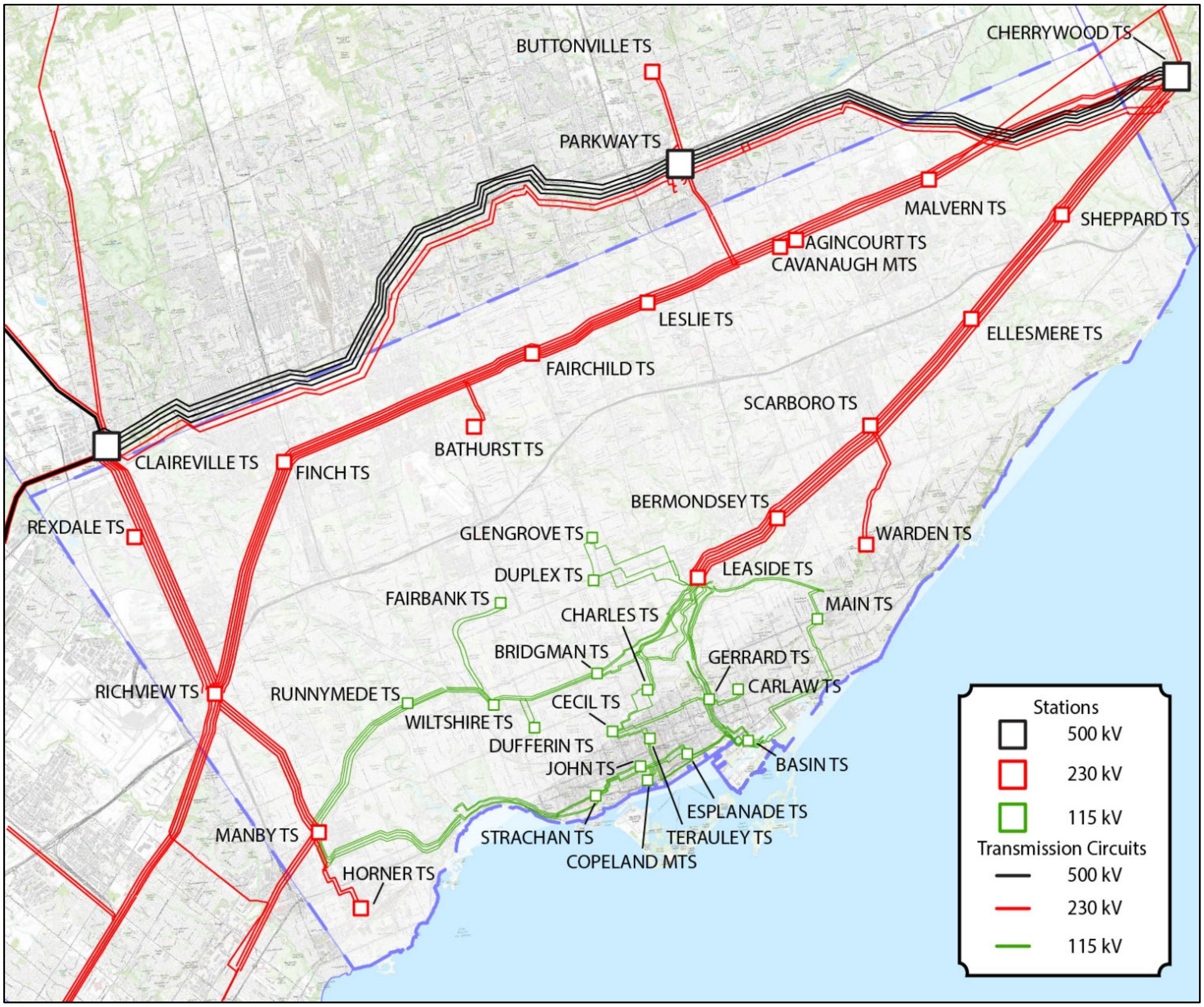
This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;

[5] The peak electricity demand in summer 2006 was 5,305 MW; in summer 2022, demand was 4,356 MW.

- Demand forecast scenarios, and electricity Demand Side Management (eDSM) and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- An overview with the linkages to the South and Central Bulk Study in Section 8; and
- A summary of engagement activities is provided in Section 9;

Figure 1 | Overview of the Toronto Region[6]



[6] IRRP regions are defined by electricity infrastructure; geographical boundaries are approximate.

2 The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Toronto Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by the North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

2.1 Status of Plans from Previous IRRP Cycles

Following the previous cycle of region planning, which concluded with the 2nd Cycle RIP report, several projects were recommended which have now been completed or are presently underway. The status of these projects is summarized in Table 4.

Table 4 | Needs Identified in the Previous Cycle with Implementation Plan Update

Infrastructure	Need	Expected In-Service
Bridgman TS	Transformer replacement (T11, T12, T13, T14)	2024
Fairbank TS	Transformer replacement (T1, T2, T3, T4)	2024
Main TS	Transformer replacement (T3, T4)	2024
John TS	Transformer replacement (T5, T6)	2025
Between Esplanade TS and Terauley TS	C5E/C7E underground cable replacement	2026
Richview TS to Manby TS	Corridor Upgrade: 115 kV double-circuit line is rebuilt to operate at 230 kV	2026
Copeland TS Phase 2	Capacity need: additional DESN added	2026
Horner TS	Installation of second DESN	2022 (Complete)
Runnymede TS	Transformer replacement (T3, T4)	2021-2022 (Complete)
Sheppard TS	Transformer replacement (T3, T4)	2021-2022 (Complete)
Strachan TS	Transformer replacement (T12)	2021-2022 (Complete)
John TS	Transformer replacement (T1, T2, T4)	2019-2021 (Complete)

2.2 IRRP Recommendations for Northern Toronto

Table 5 provides a summary of recommendations to address the needs and accommodate load growth and maintain reliability in Northern Toronto.

Table 5 | Northern Toronto Recommendations

Infrastructure	Project	Expected In-Service (based on Reference Forecast)
Station Capacity and Supply Capacity	Build Downsview MTS	2033

2.3 IRRP recommendations for Western Toronto

Table 6 provides a summary of recommendations to address the needs and accommodate load growth and maintain reliability in Western Toronto.

Table 6 | Western Toronto Recommendations

Infrastructure	Project	Expected In-Service (based on Reference Forecast)
Manby TS (West) Autotransformers	Reliance on the Manby Remedial Action Scheme	Ongoing
	Permanent transfer of Copeland MTS T2/T4 to Leaside Supply	2026
	Incremental eDSM	Ongoing
	Develop Energy Storage Systems at or downstream of the Manby West autotransformers	2029/2030
Manby TS (East) Autotransformers	Reliance on Manby RAS	Ongoing
	Permanent Load Transfer from Fairbank TS to Downsview MTS	2036
	Incremental eDSM	Ongoing
Manby to Riverside Circuits	Increase transmission capacity by upgrading circuits from Manby TS to Riverside TS[7]	2028
St Clair to Fairbank Circuits	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
Fairbank TS	Permanent Load Transfer from Fairbank TS to Downsview MTS	2037
Strachan TS	Incremental eDSM	Ongoing
Manby DESN	Monitor station capacity need as need arises towards the end of forecast	Ongoing

[7] Note that this was also recommended by the 2022 Needs Assessment Report, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto_Region_Needs_Assessment_Report_Third_Cycle_Regional_Planning.pdf

2.4 IRRP Recommendations for Eastern Toronto

Table 7 provides a summary of recommendations to address the needs and accommodate load growth and maintain reliability in Eastern Toronto.

Table 7 | Eastern Toronto Recommendations

Infrastructure	Project	Expected In-Service (based on Reference Forecast)
Leaside to Bridgman to Dufferin Circuits	Increase transmission capacity to Dufferin TS by upgrading underground circuits between Dufferin TS and the Bartlett/Dufferin Junctions	2036
	Transfer Dufferin TS load to upgraded Wiltshire TS	2036
	Develop Energy Storage Systems at or downstream of Dufferin TS	2036
Leaside to Bloor to Hearn Circuits	Increase transmission capacity by upgrading circuits from Leaside TS to Bloor JCT and from Hearn SS to Basin TS	2036
	Incremental eDSM	Ongoing
Scarboro TS, Warden TS, and Sheppard TS	Develop an additional DESN at Scarboro TS to increase capacity	2035
Glengrove TS	Investigate the feasibility of load transfers from Glengrove TS to Duplex TS	2042
Dufferin TS	Develop Energy Storage Systems at or downstream of Dufferin TS	2040
Basin TS	Develop an expansion of Basin TS or add a new station in the area.	2036
Overall Supply Capacity	Develop underwater HVDC transmission supply towards Hearn SS	2034

3 Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long-term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and identifies appropriate investments to meet the needs of a region over the next 20 years.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities
3. An IRRP, led by the IESO, which identifies the appropriate mix of investments in conservation and demand management, generation, transmission facilities or distribution facilities, or other electricity system initiatives in order to address the identified needs of a region and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. The IESO also carries out bulk system planning and Local Distribution Companies are responsible for distribution system planning. There are inherent linkages in all three levels of electricity infrastructure planning.

3.2 Toronto IRRP Development

The process to develop the Toronto IRRP was initiated in May 2023, following the publications of the Needs Assessment Report in December 2022 by Hydro One and the Scoping Assessment Outcome Report in March 2023 by the IESO. The Scoping Assessment recommended that the needs identified for the Toronto Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region. On April 5, 2024, the IESO requested an extension for the Toronto IRRP to March 20, 2025 due to the complexity of developing forecast scenarios, and additional scope included into the plan to enable the consideration of the impacts of retiring PEC, which requires the IESO to introduce additional engagement to ensure governments, businesses, developers, Indigenous communities, the City of Toronto and residents are informed and can provide input to efforts taken to decarbonize the electricity system in Toronto. On January 20, 2025, the IESO requested for an additional extension to October 31, 2025, to accommodate the results of a Local Achievable Potential Study in the IRRP in recognition of the keen interest from communities and stakeholders on renewable generation, energy storage, and energy efficiency. The IESO received approval for the extension on March 31, 2025.

4 Background and Study Scope

This is the third cycle of regional planning for the Toronto Region. The previous planning cycle for the Region concluded in 2020. For electricity planning purposes, planning regions are generally defined by the electricity infrastructure boundaries; however, the Toronto Region roughly conforms to an area within the City of Toronto municipal boundary.

The IESO acknowledges that Toronto is the traditional territory of many nations, and is committed to ongoing, meaningful dialogue with Indigenous communities to help inform long-term planning. To raise awareness about the regional planning cycle in Toronto, and invite participation in the engagement process, the IESO's engagement efforts included outreach to Indigenous communities throughout the development of the plan, including to the Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, Alderville First Nation, Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, Mississaugas of Scugog Island First Nation, and Métis Nation of Ontario.

This IRRP develops and recommends options to meet the electricity needs of the Toronto Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, eDSM, distributed generation (DG), transmission and distribution system capability, relevant community plans, age and condition of transmission infrastructure assets, and bulk transmission system needs and opportunities.

The following transmission facilities were included in the scope of this study:

Transformer stations:

Agincourt TS	Cecil TS	Fairbank TS	Leaside TS	Runnymede TS
Basin TS	Charles TS	Fairchild TS	Leslie TS	Scarboro TS
Bathurst TS	Copeland MTS	Finch TS	Main TS	Sheppard TS
Bermondsey TS	Dufferin TS	Gerrard TS	Malvern TS	Strachan TS
Bridgman TS	Duplex TS	Glengrove TS	Manby TS	Terauley TS
Carlaw TS	Ellesmere TS	Horner TS	Rexdale TS	Warden TS
Cavanagh MTS	Esplanade TS	John TS	Richview TS	Wiltshire TS

230 kV transmission circuits:

C10A	C15L	C5R	K23C	R13K	V72R	V77R
C2L	C16L	C18R	R24C	R15K	V73R	V79R
C3L	C17L	C20R	R1K	P21R	V74R	
C14L	C4R	K21C	R2K	P22R	V76R	

115 kV transmission circuits:

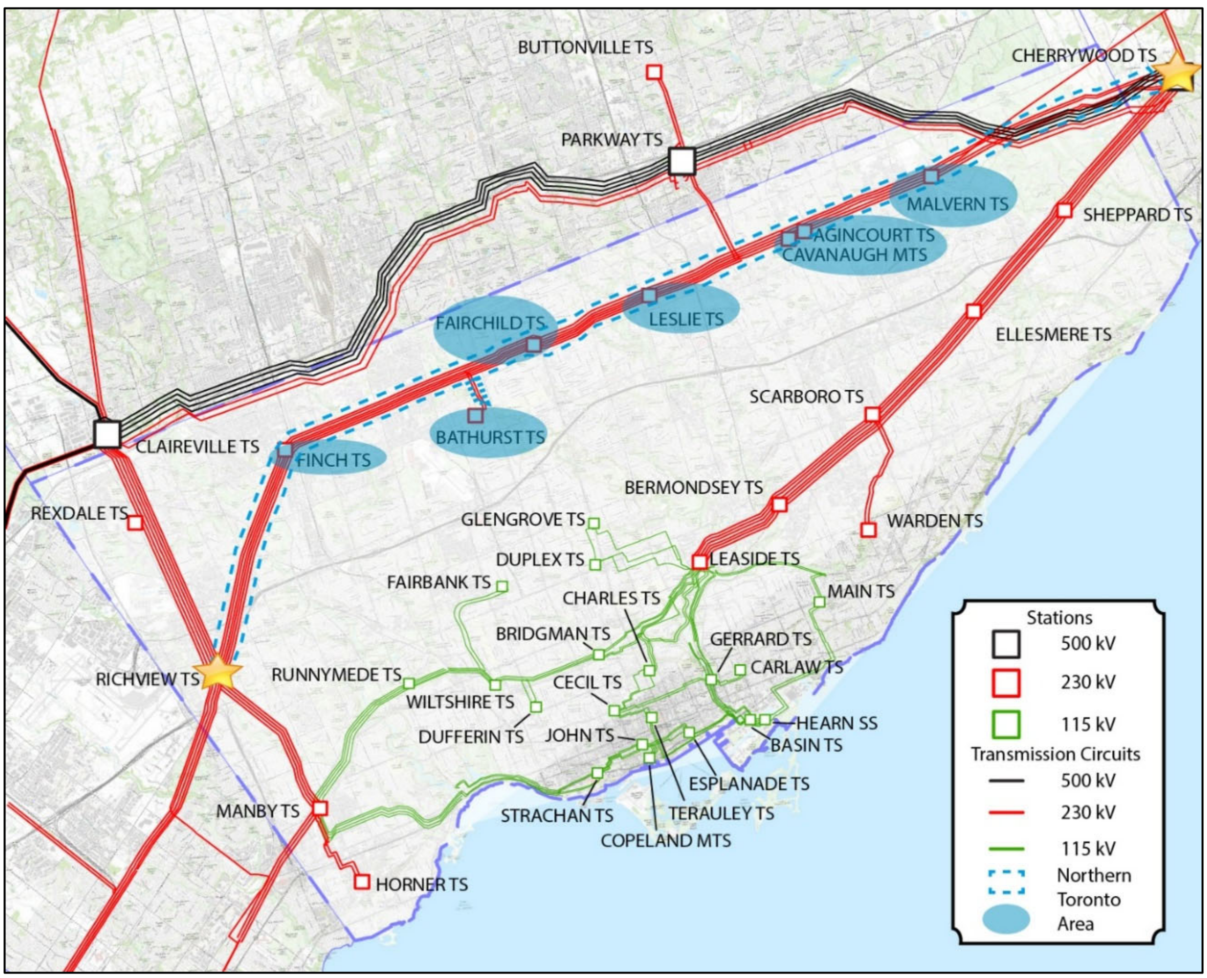
C5E	H9DE	H7L	K13J	K12W	L16D	L2Y
C7E	H10DE	H11L	K14J	L4C	L13W	
D11J	H2JK	H6LC	K1W	L9C	L14W	
D12J	H1L	H8LC	K3W	L12C	L15	
D6Y	H3L	K6J	K11W	L5D	L18W	

The Toronto Region can be further categorized into three sub-areas, which align with the main direction of incoming transmission supply in each area:

- **Northern Toronto**

Northern Toronto consists of the 230 kV circuits and stations supplied from the 230 kV transmission corridor between Richview TS to Cherrywood TS, also known as the Finch Corridor. This area primarily serves the northern areas of the City of Toronto, including North York and the northern areas of Etobicoke and Scarborough. A map of Northern Toronto is shown in Figure 2.

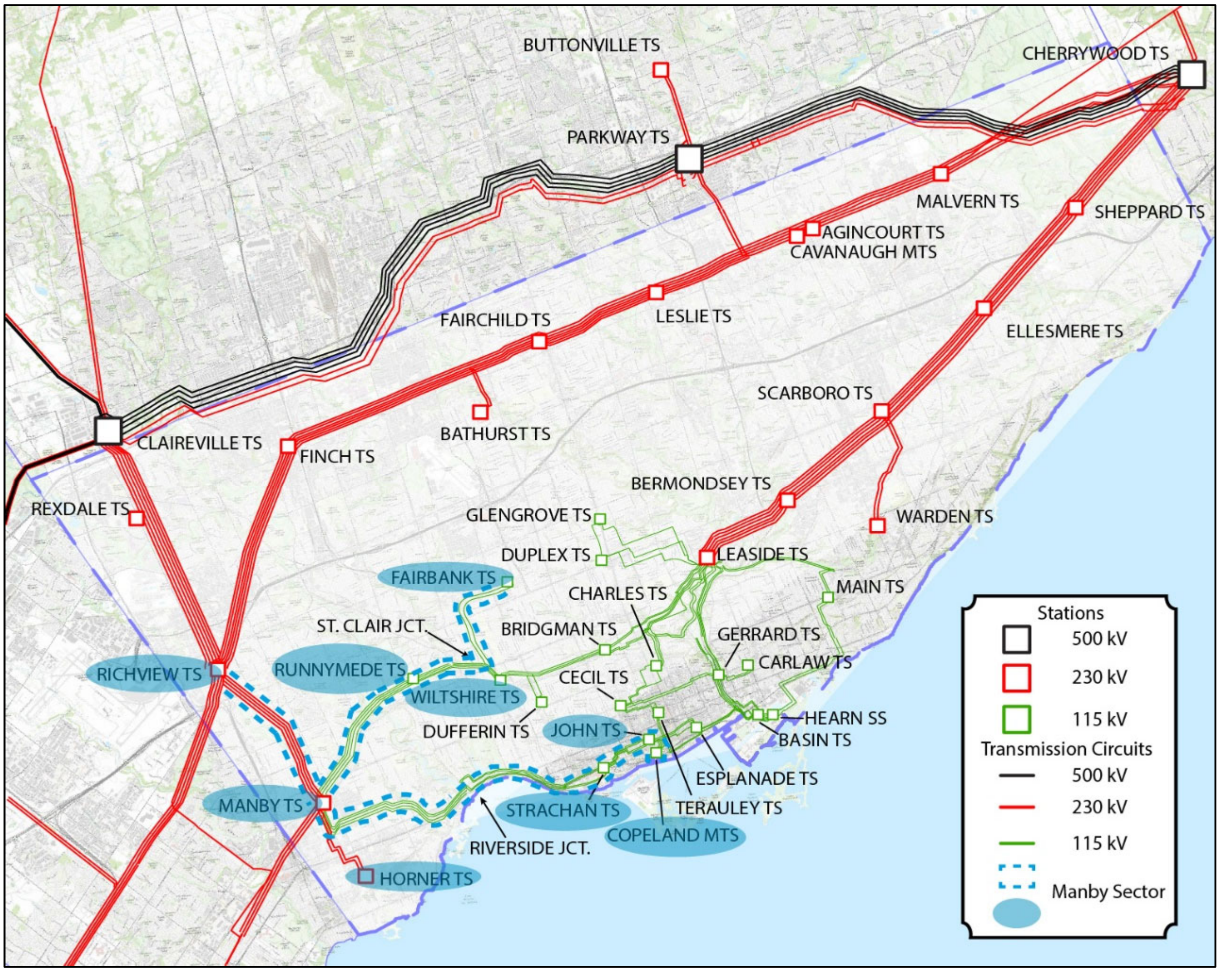
Figure 2 | Map of Northern Toronto Area



- **Western Toronto**

Western Toronto consists of the stations and circuits downstream of the Richview to Manby transmission corridor in Etobicoke. The area is serviced by a combination of 230 kV and 115 kV lines and nine stations, which provide power to southern Etobicoke and portions southwest Toronto and the downtown core. The electricity supplied by the six 115 kV stations in central Toronto and the 230 kV Horner TS in Etobicoke flows through the transmission infrastructure at Manby TS. A map of the Western Toronto area is shown in Figure 3.

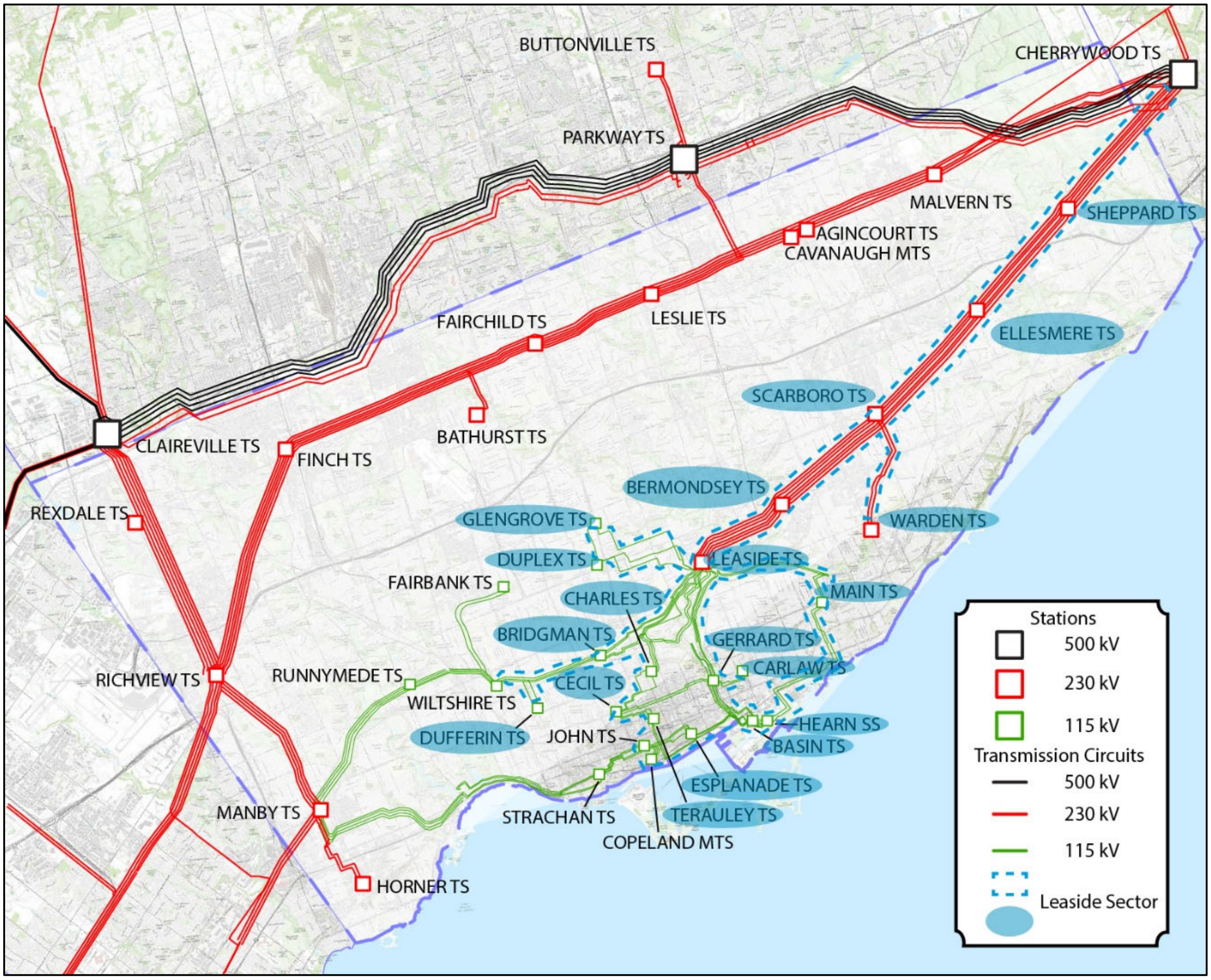
Figure 3 | Map of Western Toronto Area



- **Eastern Toronto**

Eastern Toronto includes the stations and circuits that are supplied by the Cherrywood TS to Leaside TS corridor (also known as the Gatineau Energy Corridor, and the Meadoway). These transmission lines and stations serve most of Scarborough, portions of the downtown core, East York and York. PEC is located in this area and provides local capacity that is crucial to maintaining local reliability during periods of peak demand or during transmission outages. A map of the area is shown in Figure 4.

Figure 4 | Map of Eastern Toronto Area



The Toronto IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps).
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC, NPCC and NERC standards and criteria.
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid.
- Confirming identified asset replacement needs and timing with the transmitter and the LDC.
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wire alternatives including additional eDSM.
- Engaging with communities on needs and possible alternatives.
- Evaluating alternatives to address near-term to long-term needs.
- Communicating findings, conclusions, and recommendations within a detailed plan.

5 Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Toronto region. It highlights the assumptions made for peak demand forecasts, including weather correction, and the contribution of eDSM and distributed generation (DG). Toronto Hydro, the only LDC in this region, provided forecasts for a reference case, and a high growth scenario. Toronto Hydro's scenarios considered different levels of growth for three drivers: electric vehicles, electrified heating, and data centres.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum.

The regional planning process also considered non-coincident peaks which refers to each station's individual peak, regardless of whether these peaks occur at different times. Non-coincident peaks are used to understand the potential needs of the stations.

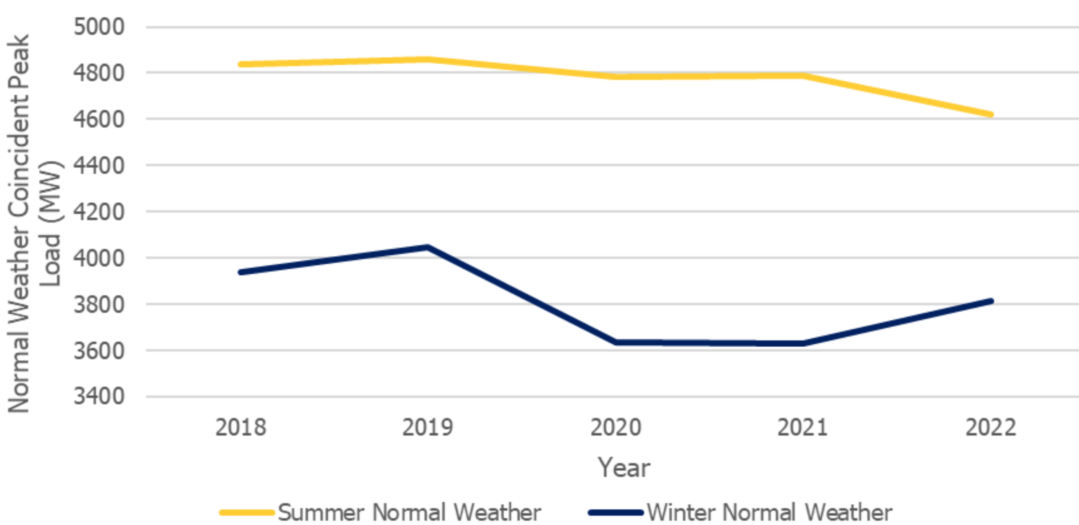
5.1 Historical Demand

The peak electricity demand within Toronto has been flat or slightly downward trending over the years preceding the forecast for this IRRP, from 2018 to 2022.

Figure 5 shows both the winter and summer coincident normal weather-corrected (adjusted to reflect normal weather conditions) historical demand for the Toronto region. Weather-corrected historical demands have been shown to remove the effect of weather on annual changes in demand. Weather-corrected demand is more appropriate for evaluating growth trends.

The weather-corrected demand for the Toronto region has averaged 4,780 MW in the summer and 3,813 MW in the winter over the last five years.

Figure 5 | Toronto Region Historical Normal Weather Coincident Forecast

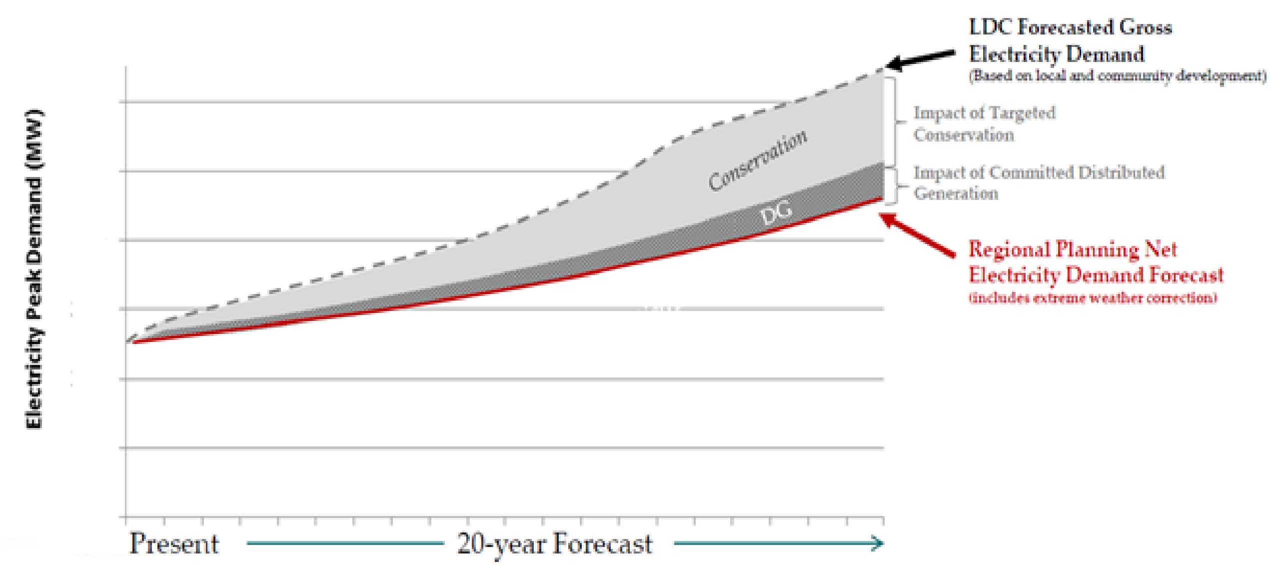


5.2 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast starting from LDC forecasts is illustrated in Figure 6. A gross demand forecast, which assume the weather conditions of a normal year based on historical weather conditions (referred to as "normal weather"), was developed by Toronto Hydro. The forecast was then modified to reflect the forecasted peak demand impacts of eDSM and DG as contracted through previous provincial programs, such as Feed-In Tariff (FIT) and microFIT. Finally, the forecast was adjusted to reflect extreme weather conditions to produce a reference forecast for planning assessments. This net, extreme-weather forecast was then used to assess the electricity needs in the region.

LDCs have a better understanding of future local demand growth and drivers than the IESO since they have the most direct involvement with their customers, connection applicants, municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the components of the demand forecast are provided in the following sections. Assumptions specific to Toronto Hydro's forecast are provided in Section 5.8. The Ontario Energy Board has also published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 6 | Illustrative Development of Demand Forecast



5.3 Gross LDC Forecast

Toronto Hydro prepared a gross demand forecast at the station level, or at the station bus level for multi-bus stations. The gross demand forecast accounts for increases in demand from new or intensified development, plus known customer connection applications. In addition, when producing the gross demand forecast, the impact of existing DG was removed, as DG impacts are accounted for later (see Section 5.5). Therefore, gross demand forecasts show the demand expected without any DG contributions, new or existing.

Toronto Hydro cited alignment with municipal plans and credited the City of Toronto as a source for input data. Toronto Hydro was also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices (natural conservation), but not for the impact of future eDSM measures (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes normal weather conditions, e.g., median weather, or 1-in-2 year expected weather, representing the station level loading at the time of the regional peak.

5.4 Contribution of eDSM to the Forecast

Electricity Demand Side Management[8] (eDSM) is a non-emitting and cost-effective resource that helps meet Ontario's electricity needs by reducing electricity consumption and peak-demand and has been an integral component of provincial and regional planning. EDSM is achieved through a mix of codes and standards amendments, as well as eDSM program-related activities. These approaches complement each other to maximize conservation results.

The estimated demand reduction from codes and standards is based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimated demand reduction from program-related activities is based on the IESO's Annual Planning Outlook eDSM savings forecasts which were informed by the 2021-2024 Conservation and Demand Management (CDM) Framework programs, federal programs expected to result in electricity savings in Ontario and forecasted long-term energy efficiency program savings aligned with the 2021-2024 framework. Through the 2021-2024 CDM Framework the IESO centrally delivered programs on a province-wide basis to residential, commercial and institutional customers, as well as Indigenous communities. Following finalization of the IRRP's demand forecast, the Ontario government directed the IESO to create the 2024-2036 eDSM Framework, which expands the scale and scope of the Save-on Energy programs, including launch of the Home Renovation Savings program for residential customers and new incentives for rooftop solar for both residential and business customers. Higher savings targets under the new framework may impact the timing or magnitude of identified needs.

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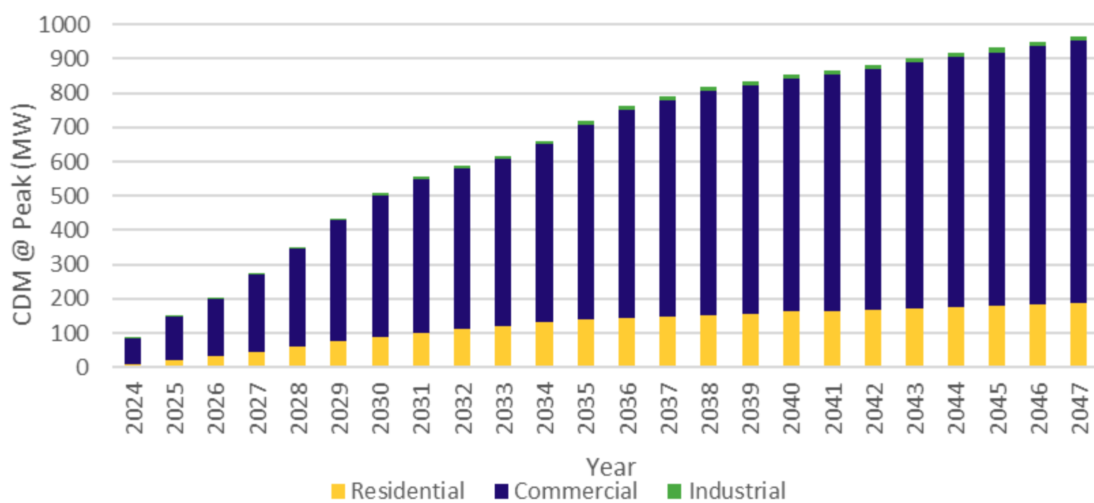
[8] In alignment with the language of the November 7, 2024 directive to the IESO regarding a new program framework for 2025-2036, this IRRP uses the term "electricity demand side management" replacing "conservation and demand management" used in previous IRRPs and other IESO planning documents.

Figure 7 and Figure 8 show the estimated total yearly reduction to the peak electrical demand due to eDSM, from codes and standards and eDSM programs, for the winter and summer peaks.

Figure 7 | Peak Winter Demand Reduction Due to eDSM

Figure 8 | Peak Summer Demand Reduction Due to eDSM



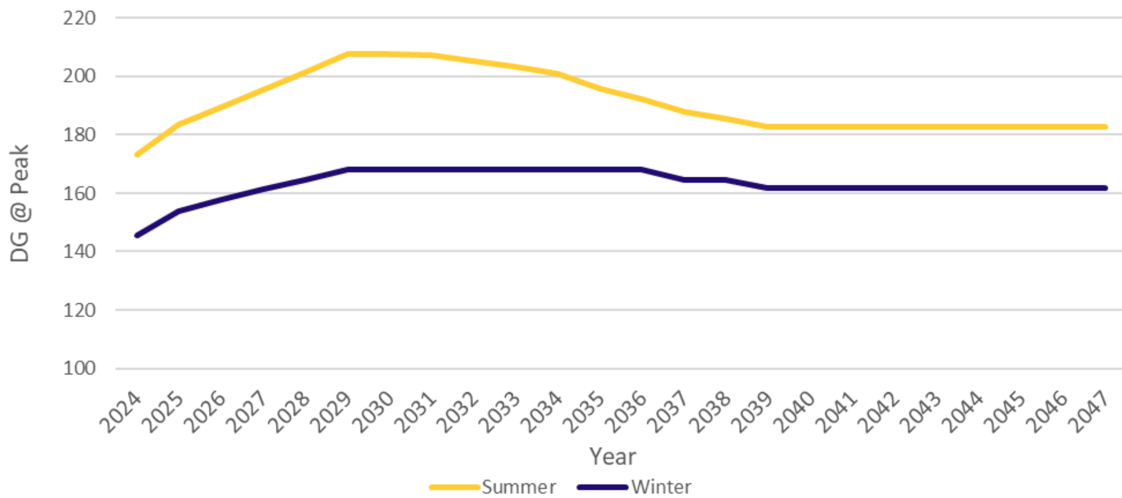
5.5 Contribution of Distributed Generation to the Forecast

In addition to eDSM resources, DG is also forecasted to offset peak-demand requirements. This includes resources contracted under Ontario's FIT and microFIT programs which increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and the associated contribution factor assumptions can be found in data tables posted on the IESO website.[9] Most of the total contracted installed DG capacity in the Toronto region is non-renewable.

[9] Regional Electricity Planning – Toronto, https://ieso.ca/torontoplanning

Figure 9 shows the estimated impact of DG on the Toronto Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast, and therefore the total contribution of DG in Toronto is higher than shown (e.g., net metered and other behind-the-meter and non-contracted facilities).

Figure 9 | Peak Demand Reduction Due to Distributed Generation



5.6 Net Extreme Weather (Planning) Forecast

The net extreme weather forecast, also known as the "planning" forecast, is traditionally a region-wide coincident forecast, meaning that each station forecast reflects its expected contribution to the regional peak demand. This supports the identification of need dates for regional needs that are driven by more than one station and allows for temporary load transfer capabilities between stations to be accounted for when assessing supply capacity.

The planning forecast is produced from two main steps: adjusting for extreme weather and converting to a net forecast.

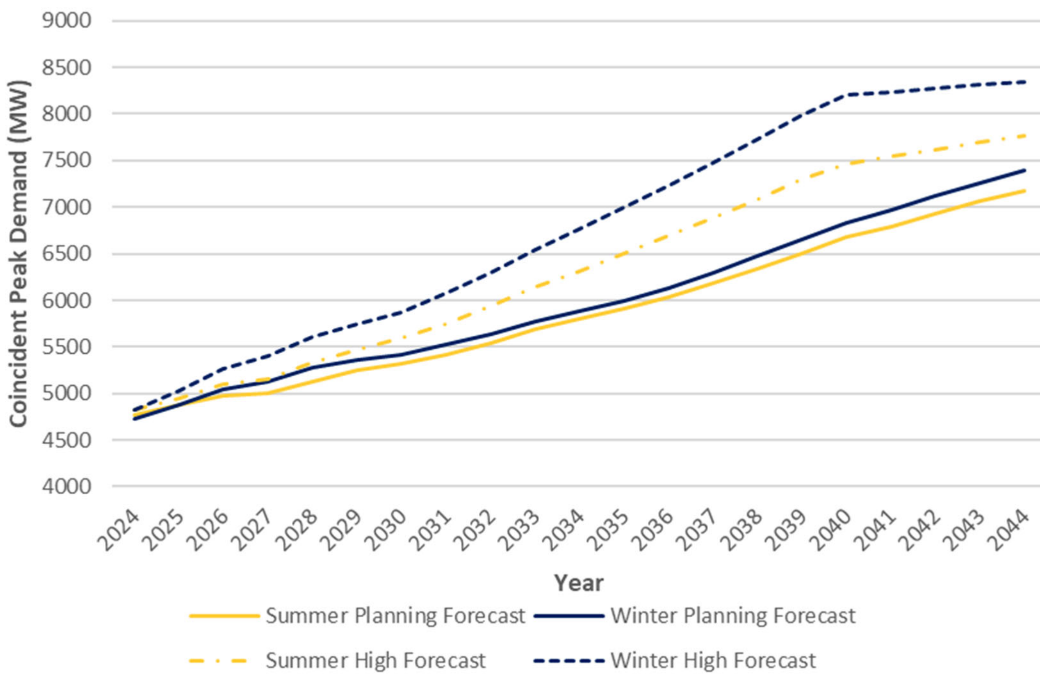
The first step is to adjust the coincident gross normal weather forecast for extreme weather conditions. This results in a coincident gross forecast which assumes extreme weather.

The last step is to adjust the resulting coincident gross extreme weather forecast for DG and conservation impacts. This is done by subtracting the forecasted DG and eDSM impacts (as described in the above Sections) from the coincident gross extreme weather forecast. This results in a coincident net extreme weather forecast, which is the "planning" forecast used to identify system needs.

For station-specific needs, a non-coincident net extreme weather forecast is used instead. The process for producing this forecast is similar to above and includes an additional step. The coincident forecast is first converted to a non-coincident forecast by applying a coincidence factor to each station. The factor is based on the station's non-coincident peaks compared to the station's historical contribution to the regional peak demand over the past five years (2018-2022 in this case).

The coincident net extreme weather reference and high electrification summer and winter forecasts (together forming the “planning” forecasts) for the Toronto Region is shown in Figure 10.

Figure 10 | Toronto Region Net Extreme Weather Coincident Forecast



5.7 Hourly Forecast Profiles

In addition to the annual peak demand forecast, hourly demand profiles (8,760 hours per year over the 20-year forecast horizon) for various collections of stations were developed to better assess non-wire alternatives to address needs. These profiles were used to quantify the magnitude, frequency, and duration of needs, as described later in Section 7. The profiles were based on historical demand data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year.

Hourly profiles of the identified needs have been posted to the IESO Toronto IRRP webpage. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan through Annual Working Group meetings until the next cycle of regional planning.

5.8 Toronto IRRP Forecast Methodology and Assumptions

Toronto Hydro, with input from the Technical Working Group, developed the forecast methodology and assumptions for the IRRP. The primary drivers of the forecast include economic growth, electrification trends, customer connection activity, and municipal development plans. These drivers are modeled to reflect their impact on electricity demand across the City of Toronto over the planning horizon. Below is a summary of the main drivers found in the forecast methodology document.[10]

5.8.1 Economic Growth

Economic activity is a foundational input to the demand forecast. Historical non-coincident system peak loads are regressed against economic indicators to establish relationships between load and macroeconomic conditions. Then, these relationships are used to project future system peaks under normal temperature conditions. Due to the lack of long-term GDP forecasts, GDP growth is held constant beyond the five-year outlook.

5.8.2 Electrification Trends

Electrification is a critical driver of future load growth, particularly in the context of market trends and the City of Toronto's Net Zero "TransformTO" strategy. The methodology incorporates three key electrification components:

5.8.2.1 Electric Vehicles

Electric vehicle (EV) adoption is forecasted across light-, medium-, and heavy-duty vehicle segments. Adoption rates vary by scenario, with the high scenario aligned with TransformTO targets (30% EVs by 2030, 100% by 2040). EV load is allocated geographically based on the distribution of existing vehicles, assuming electrification of current fleets. Hourly charging profiles are applied to estimate contributions to system peak.

5.8.2.2 Electrified Heating

Electrified heating adoption is modeled as the percentage of buildings using electric heating systems. Residential and commercial/industrial adoption rates are forecasted separately. Allocation to the bus level is based on customer counts, with higher adoption assumed in areas with greater density. Electrified heating is a significant contributor to winter peak demand.

5.8.2.3 Transit Electrification

Transit electrification is modeled based on TTC's commitment to electrify its bus fleet by 2040. The forecast assumes 190 buses are electrified annually. Space heating for transit stations is also included, modeled at 0.05 kW/m² and converted to electrical demand using a Coefficient of Performance of 2.5.

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[10] Toronto Forecast Methodology, https://ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/toronto-irrp-20240416-forecasting-methodology.pdf

5.8.3 Data Centres

Data centre development is expected to drive substantial near-term load growth. Forecasts incorporate known firm connection requests and anticipated developments. Load is allocated using a combination of proximity to existing stations, historical data centre locations, and random distribution with a bias toward downtown Toronto. Saturation is assumed by 2038 due to land constraints.

5.8.4 Customer Connection Activity

Firm customer connection requests are integrated into both the high electrification and reference forecasts. These requests provide specific timing, and demand estimates for new developments. Additionally, planned permanent load transfers are included to reflect operational changes in the distribution system.

5.8.5 Municipal Development Plans

Municipal planning documents are referenced to align the forecast with expected urban growth and electrification goals. These include:

- City of Toronto Official Plan
- Secondary Plan Areas (including the Port Lands, Update Downsview and the Golden Mile)
- TransformTO Net Zero Strategy
- TTC Green Bus Program

Load projections from City development plans are included based on high certainty of execution. These projections are derived from consultations with the City of Toronto staff and third-party consultants.

5.8.6 Scenario-Based Modeling

To address uncertainty, the reference forecast was developed using a probabilistic approach. Key drivers—temperature, economic growth, EVs, heating, and data centres—were treated as random variables. Monte Carlo simulations were used to generate a distribution of outcomes, with the median forming the final reference forecast. Before performing the Monte Carlo simulation to arrive at the reference forecast, four scenarios (High, Medium, Low, Business as Usual) were defined to reflect varying levels of policy implementation and market adoption.

6 Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of the IESO's ORTAC, Northeast Power Coordinating Council (NPCC) Directory #1 Criteria, and NERC TPL-001-4 Standards. The Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following categories.

Station Capacity Needs describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by the thermal ratings of downstream or upstream equipment, i.e., breakers, disconnect switches, medium-voltage bus or high voltage circuits; or, by voltage drop limitations, which are independent of thermal ratings.

Supply Capacity Needs describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-5, and NPCC Directory #1. LMC studies are conducted by performing power system simulation analyses using industry-standard software. A summary of the criteria used is below:

- N-1, N-1-1 and N-2,[11] events were evaluated for the forecasted extreme weather demand.
- Per section 2.6 of the ORTAC, "(w)here reliability depends on local generation, sensitivity studies should be done to assess the impact of outages of local generation." For example, such N-G-1 and N-G-2 events were evaluated assuming G3 at PEC is O/S for normal weather demand. Only subareas which are impacted by the status of PEC unit status were evaluated.
- N-1-2 scenarios were only evaluated on areas designated NPCC Bulk Power System (BPS) for normal weather demand.

[11] The ORTAC does not require double element contingency events to be evaluated for local area (non-bulk) transmission systems, unless the contingency propagates to a higher voltage level or causes a net load loss greater than 1,000 MW. However, for the City of Toronto double element contingencies were evaluated due to the social and economic importance of continuous electricity supply to the area. 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 the available system control actions between contingencies.

Asset Replacement Needs are identified by the transmitter by an asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term asset replacement needs should reflect the potential for the date to change based on updated information concerning the asset condition.

Load Security and Restoration Needs describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 2.4.10 of ORTAC.

6.2 Needs Identified in Northern Toronto

6.2.1 Station Capacity Needs

Two stations supplying Northern Toronto are expected to exceed their station capacity, namely Bathurst TS and Finch TS. Table 8 shows the year each station is expected to reach its capacity need and the MW exceedances at the end of the study period, for both the reference and high electrification forecast. These needs are primarily due to expected new community developments per the City of Toronto's Update Downsview Secondary Plan.

Table 8 | Northern Toronto Station Capacity Needs

	Reference Forecast		High Electrification Forecast	
Station	**Need Year**	**2044 Need (MW)**	**Need Year**	**2044 Need (MW)**
Bathurst TS	2034	201	2034	211
Finch TS	2038	41	2034	71

6.2.2 Supply Capacity Needs

Like the station capacity needs, the supply capacity needs in Northern Toronto are primarily due to expected new developments as a result of the City of Toronto's Update Downsview Secondary Plan. The Bathurst TS tap lines are expected to reach their LMC by 2038 in the reference forecast and 2037 in the high electrification forecast, respectively.

6.3 Needs Identified in Western Toronto

6.3.1 Supply Capacity Needs

6.3.1.1 Manby West Autotransformers

The Manby West autotransformers are expected to reach their LMC of 490 MW by 2028 in both reference and high electrification forecasts. The LMC is reached when T1/T12 exceeds its LTR following the loss of two autotransformers (as an outage + contingency scenario), with the Manby RAS fully utilized. This need arises primarily due to planned load increases at the Copeland MTS downtown, and due to growth at John TS and Strachan TS. High electrification does not accelerate the need, but it results in higher levels of unserved load.

Hydro One has indicated that Manby West T12 is expected to be replaced in 2029-2030 as per the Needs Assessment. At the time of this assessment, no new parameters were available, and the existing parameters were used. The existing T12 autotransformer has the lowest rating of the existing Manby West autotransfomers.

6.3.1.2 Manby East Autotransformers

The Manby East autotransformers are expected to reach their LMC of 500 MW by 2044 and 2035 for the reference and high electrification scenarios, respectively. The LMC is reached when T7 exceeds its LTE following the loss of two autotransformers, with the Manby RAS fully utilized. It should be noted that Hydro One has indicated that Manby East T7 and T9 are expected to be replaced in 2029-2030 as per the Needs Assessment. The existing T7 autotransformer has the lowest rating of the existing Manby East autotransformers.

6.3.1.3 Manby to Riverside Junction Circuits

The loss of K6J or H2JK plus K13J or K14J leads to K14J or K13J to exceed its short-term emergency (STE) ratings starting in 2026. This need is coincident with planned load increases at Copeland MTS. High electrification does not accelerate the need but does result in additional amounts of unserved load.

6.3.1.4 St. Clair to Fairbank Circuits

The loss of K1W or K3W will result in the companion circuit exceeding LTE rating by 2036 and 2031 for the reference and high electrification forecasts, respectively. It is recognized that Hydro One plans to replace approximately 3.2 km of the 4.5 km section of K1W and K3W with higher ampacity conductors by 2029 leaving a 1.3 km section unmodified.

6.3.1.5 Richview to Manby Circuits

The Richview to Manby circuits are currently undergoing an upgrade, referred to as the Etobicoke Greenway Project.[12] This project involves decommissioning an existing, idle 115 kV double circuit transmission like and replacing it with a new 230 kV double circuit line. This project is expected to be in-service by 2026. In addition, two of the existing 230 kV circuits from Richview to Manby are

[12] Etobicoke Greenway Project (Hydro One), https://www.hydroone.com/about/corporate-information/major-projects/etobicoke-greenway

expected to be unbundled and tie Claireville TS and Richview TS, further increasing the LMC to 1,840 MW. This unbundling project is expected to be completed no later than 2031 and was recommended in the 2019 Toronto IRRP.

Due to the expected load growth in the Manby sector, the circuits are expected to reach their new LMC by 2032 and 2030 under the reference and high electrification forecasts, respectively. This limitation is caused by breaker fail contingency at Richview, which would remove two circuits from service, resulting in a remaining circuit exceeding its long-term emergency (LTE) rating.

6.3.2 Station Capacity Needs

Three load supply stations in West Toronto are expected to exceed their station capacity, namely Fairbank TS, Strachan TS, and the Manby DESN. Table 9 shows the year each station is expected to reach its capacity need and the capacity exceedances (in MW) at the end of the study period, for both the reference and high electrification forecasts.

Table 9 | Western Toronto Station Capacity Needs

	Reference Forecast		High Electrification Forecast	
Station	**Need Year**	**2044 Need (MW)**	**Need Year**	**2044 Need (MW)**
Fairbank TS	2042	12	2036	38
Strachan TS	2039	22	2033	47
Manby DESN	2043	5	2037	21

6.4 Needs Identified in Eastern Toronto

6.4.1 Supply Capacity Needs

The following circuits and stations were identified to have supply capacity needs in Eastern Toronto.

Table 10 shows the year each need emerges and the MW exceedances at the end of the study period at the circuits and stations for the reference and high electrification forecast, respectively. Two City of Toronto Secondary Plans, namely the Port Lands redevelopment and Golden Mile, are major drivers of growth in the Eastern Toronto area.

Table 10 | Eastern Toronto Supply Capacity Needs

	Reference Forecast	High Electrification Forecast
Circuit/Station	**Need Year**	**Need Year**
L13W and L18W Bridgman x Barlet / Dufferin JCT.	2036	2029
L18W Leaside TS to Bridgman TS	2041	2033

	Reference Forecast	High Electrification Forecast
Circuit/Station	**Need Year**	**Need Year**
L15 Leaside TS x Bridgman TS	2036	2026
L14W Birch JCT x Bridgman TS	-	2037
H1L/H3L Leaside TS x Bloor St.	2036	2036
H1L/H3L Hearn SS x Basin TS	2041	2037
C2L + C3L Double Contingency	<2025	<2025
Leaside Area Voltage Support	2038	2034

6.4.1.1 Leaside to Bridgman to Dufferin Circuits

The circuits that supply Bridgman TS and Dufferin TS from Leaside TS (namely L13W, L15, L14W, and L18W) are expected to reach their LMC by the 2036 winter reference forecast (potentially as soon as 2026 for the high electrification forecast). The most limiting element is L15, which will overload following the loss of L13W and L18W. Overloading on other circuits (e.g., L14W and L18W) occurs later but is caused by the same growth drivers at Dufferin TS and Bridgman TS.

6.4.1.2 Leaside to Bloor Circuits

The sections between Leaside TS and Bloor Junction (JCT) on H1L and H3L are expected to be overloaded by 2036, for both the reference and high electrification case, during an outage at PEC (G3 unit) followed by a breaker failure at Hearn. In their Needs Assessment, Hydro One indicated the overhead sections of H1L and H3L between Leaside TS and Bloor JCT are to be replaced with the largest size possible conductor while retaining existing tower structures.

6.4.1.3 Hearn to Basin Circuits

The 0.5 km sections between Hearn SS and Basin TS on H1L and H3L are expected to be overloaded by 2041 and 2036 for the reference and high electrification case, respectively. These circuits will exceed their LTE ratings following the loss of the companion circuit. This need is driven by the additional load attributed to the Port Lands Secondary Plan development.

6.4.1.4 Cherrywood to Leaside Circuits

The loss of two of the Cherrywood TS to Leaside TS circuits, namely C2L and C3L, results in voltage instability in the Leaside sector when loading is sufficiently high. This need exists in the current system and is managed by control actions.

As load continues to grow, the contingencies that can lead to voltage instability expands beyond what can be managed with existing control actions. Instability is forecast to occur between 2035 and 2039 for the loss of C16L or C17L followed by the loss of two elements that remove two Cherrywood to Leaside (CxL) circuits and two capacitors at Leaside TS (i.e., specific Leaside breaker failures). In subsequent years this need continues to expand to include other combinations of transmission equipment outages.

Given ORTAC's requirement of keeping within a 10% margin on voltage stability, LMC of the Cherrywood to Leaside circuits is about 2,610 MW, resulting in a need date corresponding to 2038 and 2034 for the reference and high electrification forecasts, respectively. The size of the need (due to the demand forecast) and considering a scenario with reduced reliance on PEC necessitates that a new supply be built to Toronto. More details can be found in Section 6.5 below.

6.4.2 Station Capacity Needs

Six load supply stations in Eastern Toronto are expected to exceed their station capacity, namely Scarboro TS, Sheppard TS, Warden TS, Glengrove TS, Dufferin TS, and Basin TS. Table 11 shows the year each of these needs emerges, and the MW exceedances at these stations at the end of the study period for the reference and high electrification forecast, respectively.

Table 11 | Eastern Toronto Station Capacity Needs

	Reference Forecast		High Electrification Forecast	
Station	**Need Year**	**2044 Need (MW)**	**Need Year**	**2044 Need (MW)**
Scarboro TS	2035	166	2034	181
Sheppard TS	2038	27	2033	48
Warden TS	2036	28	2032	42
Glengrove TS	2042	10	2035	31
Dufferin TS	2040	27	2033	66
Basin TS	2036	79	2036	81

6.5 Need for New Supply in Eastern Toronto

Electricity system needs in the East Toronto area in the medium term (up to 2035) are driven primarily by local growth and development plans, including secondary plans for the Port Lands district and the Golden Mile in Scarborough. Together with other policy and economic drivers such as urban intensification, electrification and decarbonization, the electricity demand in East Toronto is expected to exceed the capacity of the transmission system within the next 10 to 15 years. The largest of the needs involves the 230 kV transmission supply from Cherrywood TS. More specifically, load growth will cause exceedances of the line capacity of the 230 kV transmission circuits between Cherrywood TS and Leaside TS, and the autotransformers at Leaside TS. With PEC in-service, planning studies show that credible planning contingencies such as the loss of two 230 kV supply circuits will result in voltage instability by 2038.

6.5.1 Portlands Energy Centre Scenario

The IRRP investigated a scenario with PEC out-of-service (i.e., not operating/contributing to meeting demand in Toronto). This scenario was driven by a need to consider options for maintaining cost-effective and reliable electricity supply given the facility's contract expiration date of April 2034. Both the *Pathways to Decarbonization* and *Powering Ontario's Growth* reports indicated a need to study the transmission reinforcements required to eventually phase out local gas-fired generation in consideration of the development lead time to implement transmission alternatives. The retirement scenario is also responsive to local community opposition to the continued operation of the gas plant in the urban centre, and a 2024 Toronto City Council resolution requesting the IESO to study phasing out PEC by 2035.[13] Given the facility's contribution to local reliability, the IRRP technical studies confirmed that a transmission reinforcement would be needed to accommodate a future without PEC, and must be in place before the facility can retire With or without the capacity contribution of PEC, the transmission is still needed to supply the forecasted load growth. The IESO will continue to investigate possible measures that can reduce local reliance on PEC in the interim period while a transmission solution is being implemented.[14]

In addition, while local reliance on PEC will be reduced once the Third Line is in place, it may still be needed to meet the provincial grid's peak needs into the 2030s. The Toronto IRRP is focused on local supply and does not address matters of provincial supply.

6.6 Addressing Resilience of Toronto's Electricity System

Through the engagement of the Toronto IRRP, the Technical Working Group heard that system resilience should be an important consideration to the plan. Based on this feedback, the Technical Working Group considered resilience in the development of IRRP options, and to inform future planning.

6.6.1 Flooding of Manby Transformer Station

In July 2024, Toronto experienced a severe summer storm that caused flash floods across the city. One of the most significant impacts was the flooding at Manby TS, which is one of two major transmission supply paths into downtown Toronto. The storm caused widespread outages, affecting the electricity supply to about 190,000 customers.[15] The flooding of Manby TS and subsequent load loss underscores the importance of system resilience especially from extreme weather events, and considering climate change.

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[13] Toronto City Council Meeting, Item – 2024.MM19.9, https://secure.toronto.ca/council/agenda-item.do?item=2024.MM19.9

[14] Some non-wires alternatives may also serve to mitigate against possible timeline risks of the transmission solution.

[15] Severe Toronto storm causes flooding, major power outages | CBC News

7 Plan Options and Recommendations

This section describes the options considered and offers recommendations to address the needs in the Toronto Region. In developing the plan, the Technical Working Group considered a range of integrated options, which included combinations of options. These options were screened and further evaluated based on key considerations including technical feasibility, cost, lead time, other benefits, and consistency with longer-term needs in the area.

Generally, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new transmission or distribution infrastructure. These are commonly referred to as "wire" options and can include utility investments such as new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing lines and stations, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing LMC. These are commonly referred to as "non-wire" options and can include measures such as locally sited generation or storage resources connected to the transmission system, distributed energy resources including generation and demand response that are distribution-connected, or additional eDSM.

Section 7.1 begins with an in-depth overview of options considered in IRRPs. Section 7.2 provides a summary of the Local Achievable Potential Study, and Section 7.3 speaks to thermal energy networks and the opportunity to coordinate with long-term electricity system planning. Section 7.4 describes the screening approach used to assess which needs would be best suited for wires and/or non-wires options. Subsequently, Sections 7.6 to 7.9 present the options ultimately developed and evaluated according to cost and other factors to inform the IRRP recommendations.

7.1 Options Considered in the IRRP

Both wire and non-wire options were considered in the development of this IRRP. Wire options are well suited for addressing a range of power system reliability issues and generally provide a substantial increase in the LMC for both summer and winter peak seasons. Non-wire options such as eDSM, locally sited renewable resources or storage generally help to maintain or reduce energy demand requirements, with significant variances among these various resources in terms of their ability to target the winter and/or summer peak demand. To evaluate non-wire options such as local generation or energy storage, the additional step of creating hourly load profiles is required, as described in Section 5.7. Suitable technology types are chosen by examining the "unserved energy" profile, which represents the hourly duration and magnitude of the demand that exceeds the system LMC. The load profile indicates the duration, magnitude as well as the frequency and total energy requirement associated with each need. Hourly profile data for the Toronto IRRP have been published on the IESO's webpage.

Planning level cost estimates for wire options were based on input provided by Hydro One and Toronto Hydro, as well as informed by transmission costs from other IESO planning studies and industry benchmarks. Cost estimates for non-wire options were based on benchmark capital and operating cost characteristics for each resource type and size. Due to policy considerations and community preferences, new natural gas-fired generation was not considered an option for addressing local needs in the City of Toronto. Energy storage, solar PV, and wind generation were considered.

The assumed energy efficiency savings from programs under the 2021-2024 CDM Framework and Save on Energy brand were included in the demand forecast, as discussed in the Section 5.4. The IESO was also directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is one tool that is available to target the delivery of additional savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors (previously "CDM Guidelines") to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. Additional demand savings from the eDSM framework beyond those already embedded in the forecast were evaluated as potential options to address identified regional needs. Generally, eDSM is suitable for needs where growth is gradual to and the magnitude of the overload relative to the total demand is small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.4, as part of the options screening.

For both wire and non-wire options, the upfront capital and operating costs are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wire option (typically 70 years for transmission line infrastructure). The net present value (in 2024 $CAD for this report) of these levelized costs is the primary basis through which feasible options are compared.

It is important to recognize the error margin around cost estimates at the planning stage. These costs serve to enable comparison of the different options during the IRRP. The transmitter-led RIP (following the IRRP) is an opportunity to carry out further analysis allowing for cost estimates to be refined prior to implementation. The Technical Working Group can revisit specific recommendations if cost estimates or other parameters change significantly. Further, certain options including non-wires could be tested through pilot or demonstration projects in cases where other barriers or implementation challenges need to be worked through (e.g., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints).

7.2 Local Achievable Potential Study

To further enhance and supplement the regional planning work underway for Toronto, the IESO retained energy consultancy ICF International to conduct a local achievable potential study (LAPS) to identify the potential for additional eDSM programming, above and beyond the already planned eDSM included in the IRRP demand forecasts, to cost-effectively meet regional needs. The purpose of the study was to identify and quantify both electricity energy and demand savings potential attainable through a range of behind-the-meter DERs, with associated costs. Energy efficiency, demand response, and other resources including solar PV and energy storage were considered over the 20-year period. Although a long-term view was included in scope for the LAPS, there remains much uncertainty about the timing of technology advancements in the DER space. The study results will inform decisions in the near-term (first five years of the plan), while still allowing for innovation to happen in eDSM and DER programs/procurements and/or pilots and demonstration projects. The LAPS results are not intended to represent a maximum of the amount of savings that may be achieved through province-wide and/or local program performance; and it is not intended to preclude new measures from being introduced as program offerings in the future.

The LAPS was carried out for two local forecasts aligned with the IRRP reference and high demand forecast scenarios. For each scenario, the study used a bottom-up approach to determine the energy savings potential from technical, economic and achievable perspectives.

- Technical Potential is the estimated savings resulting from the implementation of all technically feasible measures, ignoring cost-effectiveness, customer awareness, equipment turnover rates, or other "real world" barriers.
- Economic Potential is the savings resulting from the implementation of all technically feasible measures that pass a cost-effectiveness test (Program Administrator Cost or "PAC" test).
- Achievable Potential is the final savings remaining after adoption rates over the period of the study are applied and is intended to represent a realistic estimate of the savings that could be acquired through programs.

These savings are simulated at the building level using a "digital twin" model for the residential and commercial sectors and aggregated to the station level for each scenario. Measures in scope include:

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

Under the reference demand scenario, the LAPS estimates a total of 1,167 MW of summer peak demand savings potential and 878 MW of winter peak demand savings potential over 20 years. After deducting savings from planned eDSM already captured in the demand forecast this represents an incremental opportunity of 320 MW of summer and 121 MW of winter peak demand savings.

The LAPS Final Report will be published and made available on the IESO website. These documents provide detailed descriptions of the methods, data sources, input assumptions, and results of the study.

In reviewing the LAPS results, it is important to acknowledge that planners must consider several factors in assessing whether estimated eDSM potential can help address an identified need. These include:

- How much of the estimated achievable potential is incremental to the savings already captured in the eDSM savings forecast?
- Can the incremental eDSM potential satisfy both summer and winter needs if applicable?
- How much incremental achievable potential is available in the specific need area (e.g. additional potential in Etobicoke cannot help a station capacity need in Scarborough)?

- How does the timing of incremental eDSM potential becoming available align with the timing of need?

These key considerations will help inform the implementation of IRRP recommendations to acquire incremental eDSM savings throughout Toronto.

7.3 Thermal Energy Networks

The City of Toronto presented to Toronto Hydro and the IESO results of their *Toronto Port Lands Demand Justification & DER Potential Assessment*. Their study reviewed the potential for thermal energy networks (TENs) and stringent Building Performance Standards to reduce the summer and winter peak demand impact of planned mixed-use urban development in the Port Lands. The scope of this study was specifically the loads served, or to be supplied by Basin TS.

The Technical Working Group recognizes the potential for district energy to continue to be a valuable resource that will contribute meaningfully to the City of Toronto's future energy needs, particularly in the context of reducing emissions and meeting the city's climate goals. District energy systems distribute thermal energy to multiple buildings and offer scalable, efficient, lower carbon solutions that align with the City of Toronto's TransformTO climate action plan and net-zero targets. The successful development and integration of district energy projects will require continued leadership from the City of Toronto and active participation from district energy service providers, developers and customers.

Municipal coordination, policy support, and investment are essential to unlocking the full potential of district energy as part of a diversified and resilient energy strategy for the City. The Technical Working Group recommends the City of Toronto keep Toronto Hydro informed of plans to implement district energy systems to ensure their impact on the electricity system can be properly assessed in local and regional plans. As it will take new developments like the Port Lands, as well as Downsview and the Golden Mile several decades to be fully realized, there is time for coordinated planning and action to understand the potential co-benefits of new thermal energy networks for deferring or avoiding additional investment in electricity transmission and distribution infrastructure.

7.4 Options Screening Results

As explained in the previous section, an array of options to meet local needs is developed during an IRRP. Each of these options is screened based on whether it meets the technical requirements for a solution, and the technically feasible options are then evaluated to arrive at a set of recommended options. Options are preferred based on their cost-effectiveness, as well as other decision-making factors including risk mitigation as it relates to future costs, implementation considerations, and community and stakeholder preferences and feedback, amongst other considerations.

Screening occurs early in the IRRP study after local reliability needs are known but before detailed analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 11 and further discussed in the next sections. A summary of the options screening results for the Toronto IRRP is provided in Table 12.

Figure 11 | IRRP NWAs Screening Mechanism

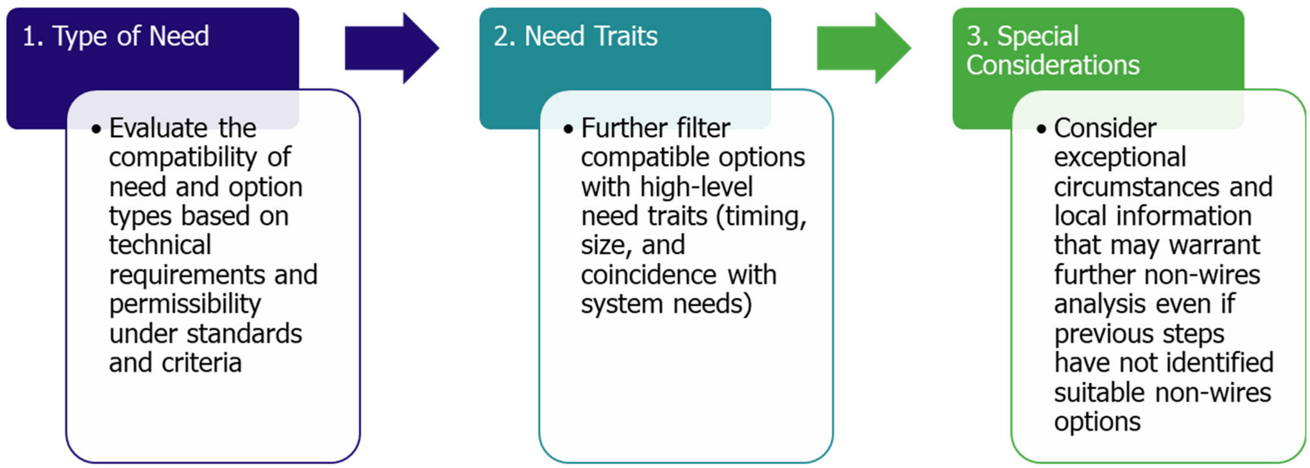


Table 12 | Options Screening Results for Toronto Needs

Area	Need	Screened In	Screened Out
Northern Toronto	**Supply Capacity**	• Wires (new transmission lines) • Wires plus integrated approaches including additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation
	Station Capacity	• Wires (new station) • Wires plus integrated approaches including additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation
Western Toronto	**Supply Capacity**	• Wires (upgrades to existing lines) • Energy Storage[16] • Wires plus integrated approaches including energy storage, additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation

[16] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

Area	Need	Screened In	Screened Out
	Station Capacity	• Wires (new or expanded stations) • Wires plus integrated approaches including additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation
Eastern Toronto	**Supply Capacity**	• Wires (new and upgraded transmission lines) • Wires plus integrated approaches including energy storage, additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation
	Station Capacity	• Wires (new or expanded stations) • Wires plus integrated approaches including additional eDSM, DERs	• Transmission connected generation such as wind generation, and wind and/or solar + energy storage • Gas generation

7.5 Options and Recommendations for Northern Toronto

In Northern Toronto, the supply and station capacity needs have common drivers. Load growth at both Bathurst TS and Finch TS (and the circuits supplying the two stations) will exceed their capacity limits due to electricity demand growth driven by the Update Downsview Secondary Plan. As this Secondary Plan involves brand new communities, new transmission and distribution infrastructure will be needed to supply them. A new Downsview MTS would also provide an opportunity to offload Bathurst TS, Finch TS, Fairchild TS and Fairbank TS, thereby ensuring these stations remain within their capacity limits.

As a result, Toronto Hydro, as part of their 2025 Distribution System Plan, proposed a new transformer station named Downsview MTS to be connected to the Finch Corridor circuits. This new station was approved by the OEB as part of Toronto Hydro’s recent rates application. The Technical Working Group supports this decision and continues to recommend Downsview MTS be built to meet needs of the area.

As part of the IRRP, two potential connection arrangements were studied for Downsview MTS. The first arrangement would involve building a Downsview Switching Station (SS) which would connect all six circuits on the Finch Corridor to Downsview SS which would then feed Downsview MTS. The second arrangement would involve connecting Downsview MTS directly to two of six Finch Corridor circuits.

7.5.1 Wires Options – Build Downsview SS and Downsview MTS

The proposed Downsview SS would consist of two 230 kV buses each tapping three of the six 230 kV circuits in the Finch Corridor. The two supplies for Downsview MTS would then come from the two 230 kV buses at Downsview SS. The construction of Downsview MTS/SS, along with the load transfers to Downsview from the surrounding load stations, defers the expected timing when sections of P21R reaches its LTE ratings for select N-1-1 events to 2042 (for both the reference and the high electrification forecast). This exceedance can be mitigated if manual load rejection (up to 150 MW) post contingency at Downsview MTS is possible within 15 minutes, as the STE rating is not forecast to be exceeded. Alternatively, small amounts of incremental eDSM and/or DER starting in 2040 would defer the need past the forecast period (i.e., beyond 2044).

7.5.2 Wires Options – Connect Downsview MTS directly to two of Finch Corridor Circuits

An alternate arrangement was assessed to determine if Downsview MTS could be connected directly to two of the six circuits between Richview TS and Cherrywood TS/Parkway TS thereby eliminating the need for Downsview SS. The pairs of circuits assessed in this alternative are listed below:

1. C4R and C18R
2. C4R and C20R
3. C4R and P22R
4. C5R and C18R
5. C5R and C20R
6. C5R and P22R
7. P21R and C18R
8. P21R and C20R
9. P21R and P22R

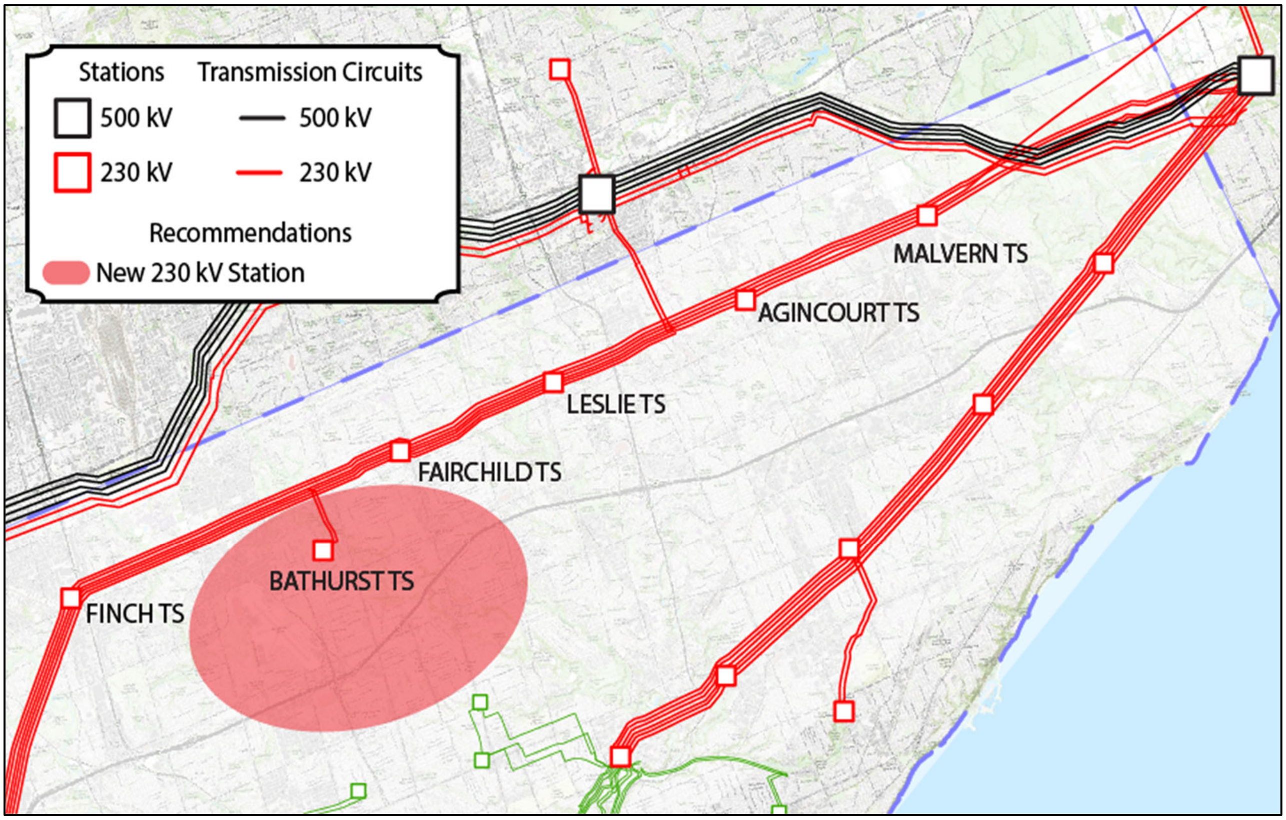
Study results show that any option involving P21R or P22R (i.e., pairs 3, and pairs 6 – 9) are the most limiting arrangements. Any option involving these circuits leads to supply limitations starting in 2038 (via the loss of non-Parkway to Richview circuit overloading the remaining Parkway to Richview circuit). For all the other options, the six circuits between Richview TS and Cherrywood TS/Parkway TS remain under LTE ratings within the forecast period, for all the single and multiple-element contingencies considered.

7.5.2.1 Recommendation for Northern Toronto

The studies demonstrate both connection arrangement options allow for the reliable connection of the new Downsview MTS and its associated forecast demand. It is important to note that while the Downsview SS and Downsview MTS combined option was approved by the OEB, while the further analysis carried out in this IRRP shows that connecting Downsview MTS directly to two of the Finch Corridor circuits leads to lower overall costs for Toronto Hydro.

This recommended action is expected to cost approximately $170 Million in Canadian dollars and is expected to have a lead time of five to seven years.

Figure 12 | Recommended Option for Northern Toronto



Therefore, the Technical Working Group recommends that Toronto Hydro proceed with Downsview MTS, and that Toronto Hydro and Hydro One finalize their preferred connection arrangements in the upcoming RIP, keeping in mind that a solution should be in place by 2034.

7.6 Options and Recommendations for Western Toronto

In the following sections, the options that passed the initial screening to address system needs in Western Toronto are discussed. The Western Toronto supply capacity needs, as discussed in Section 6.3.1, include overloads at the Manby TS autotransformers (Manby West and Manby East), the Manby TS to Riverside Junction 115 kV transmission circuits, the Richview TS to Manby TS 230 kV circuits, and the St. Clair to Fairbank TS circuits. Stations in Western Toronto that are expected to reach their capacity in the study period include Fairbank TS, Strachan TS, and the Manby DESN.

The recommended actions for Western Toronto are a mix of integrated solutions including investments in wires and non-wires.

7.6.1 Options for Addressing Manby West Autotransformers

7.6.1.1 Wires Options – Manby Crossover Option

One option that could alleviate autotransformer loading at Manby West involves swapping K13J (or K14J) terminals at the Manby West 115 kV yard with the any one of the Manby to Wiltshire circuits in the Manby East 115 kV yard ("Manby Crossover Option"). This would result in more even distribution of power flow between the Manby East and Manby West autotransformers. It also provides additional system redundancy in the event of a loss of an autotransformer in either yard as it will allow for Manby East to support Manby West and vice-versa. Further, implementing this option would reduce the need to rely on the existing Manby RAS until the 2042 high electrification forecast materializes.

Hydro One estimates this option would cost between $15 million and $20 million to implement. However, short circuit studies performed by Hydro One demonstrate that the Manby Crossover Option will greatly increase fault levels at Manby, imposing a severe constraint on future system development including the addition of any new DERs in the area. Additional costs are expected to remediate the resulting short circuit limitations at impacted stations. Future studies would be needed to determine the feasibility of addressing these limitations and the additional costs.

7.6.1.2 Wires Options – Reliance on Manby RAS

The Manby Remedial Action Scheme (Manby RAS) is an existing scheme that allows operators to arm certain loads for rejection upon the loss of one or more autotransformers at Manby TS. For example, upon the loss of any Manby West autotransformer, transferring the entire Copeland MTS facility to Leaside supply in case of the loss of a second autotransformer defers the needs past the end of the study period for the high electrification forecast, provided up to 150 MW of load rejection between John TS and Strachan TS is used following the loss of the second autotransformer. This level of load rejection is allowable per the IESO's ORTAC.

The HVDC Third Supply increases available capacity to the Leaside sector and allows for this option to be implemented. It should be noted that this option would limit the emergency load transfer of Esplanade TS, which is normally supplied by Leaside, to Manby supply in an emergency event. Further studies, including extreme contingency events and their likelihood can inform whether future actions to enhance emergency load transfer capabilities should be explored.

7.6.1.3 Wires Options – Permanent transfer of Copeland MTS T2/T4 to Leaside Supply

This option involves permanently transferring supply of Copeland MTS T2/T4 from Manby to Leaside supply starting in 2026. This will alleviate overloading issues at the Manby West autotransformers.

7.6.1.4 Non-wires Options – Incremental eDSM

Informed by the local achievable potential study, incremental eDSM potential was estimated at the stations downstream of Manby West, namely Strachan TS and John TS. This incremental eDSM is in addition to that to the planned eDSM that is already assumed in the demand forecast. Table 13 shows the incremental eDSM potential at five-year intervals over the planning horizon. It is important to note that the planned and incremental eDSM savings also provide a net provincial system benefit by avoiding generation at peak.

Table 13 | Incremental eDSM at Strachan TS and John TS

Station	Incremental eDSM (MW, cumulative)			
	2025	2030	2035	2040
Strachan TS	3	9	13	16
John TS	1	7	14	17

7.6.1.5 Non-wires Options – Energy Storage Systems

The hourly profile of this need aligns well with the capabilities of an energy storage solution.[17] Table 14 shows the minimum capacity and energy build-out requirements, assuming either a single ESS or multiple ESS that are aggregated, to meet the need on an annual basis. Locating ESS in Manby West will not only serve both the identified regional need but will also contribute to provincial resource adequacy. Note that for the ESS to address the Manby West autotransformer need, they would need connect to the transmission system via any combination of K13J, K14J, H2JK, or K6J circuits or the Manby 115 kV bus. The ESS can also be connected to the distribution system if they eventually connect downstream of:

- Strachan TS
- John TS
- Copeland MTS (T1/T3 only[18])

Table 14 | Requirements for ESS to meet Manby West Autotransformer Need

Year	ESS Incremental Capacity Requirements (MW)	ESS Incremental Energy Storage Requirements (MWh)
2029	5	20
2030	6	35
2031	6	44
2032	9	75
2033	16	162
2034	-	-
2035	-	-
2036	-	-
2037	7	70
2038	9	95
2039	8	70
2040	6	60
Total	**72**	**631**

[17] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.
[18] Assuming Copeland MTS T2/T4 is permanently transferred to Leaside supply.

This local ESS is expected to have a net system cost of $0 to $30 million, which accounts for the broader system benefit it enables through a reduction in overall provincial capacity needs. The combination of addressing local and provincial needs, along with using less land and having a shorter lead-time than other NWAs, make this option an attractive one for the Manby West Autotransformer need.

7.6.1.6 Recommendation to Address Manby West Autotransformer Needs

The Technical Working Group recommends the following integrated set of options to address the Manby autotransformer need:

- Continued reliance on Manby RAS
- Permanent transfer of Copeland MTS T2/T4 to Leaside Supply
- Incremental eDSM
- Energy Storage Systems

The above options are recommended as they take advantage of the existing transmission system's transfer and operational capabilities (e.g., reliance on existing Manby RAS and permanent transfer of Copeland MTS T2/T4). The permanent transfer of Copeland MTS T2/T4 will need to be in place by 2026 to address the supply capacity needs in the Manby to Riverside Junction circuits prior to its upgrade as discussed in Section 7.6.3 below, according to both the reference and high electrification forecasts. Incremental eDSM can be targeted as part of the current eDSM framework.

An ESS (or multiple ESS) capable of meeting the incremental capacity and energy requirements is also recommended to mitigate the risk of load rejection being used. Local ESS connected to the aforementioned stations and circuits can provide local capacity should an autotransformer suffer an outage during a period of high demand.

The IESO and Toronto Hydro will need to collaborate to scope the technical requirements, achievable implementation timelines, and decide on the most suitable procurement approaches. The IESO and Toronto Hydro will ensure the Technical Working Group is kept updated on progress and any challenges through annual Technical Working Group meetings.

Although the Manby Crossover option greatly increases capacity, the short circuit limitations at Manby do not allow it to be recommended at this time. In order to preserve this option for the future, it is recommended that Hydro One determine the scope a detailed short circuit study for the Toronto Region. This study scope should include timelines for completing the studies, with the objective of identifying options that can alleviate transmission short circuit constraints in Toronto, should any exist. Insights from this study will allow this option to be more fulsomely considered in future regional plans.

A summary of the expected costs and lead times for the recommended wires options is provided in Table 15.

Table 15 | Recommended Wires Options to address Manby West Autotransformer Needs

Recommendation	Capital Costs ($M CAD)	Lead Time
Reliance on Manby RAS	N/A	Ongoing
Permanent transfer of Copeland MTS T2/T4 to Leaside Supply	N/A	1 year

7.6.2 Options for Addressing Manby East Autotransformers

7.6.2.1 Wires Options – Reliance on Manby RAS

This option involves continuing to rely on the existing Manby RAS. Upon the loss of any Manby East autotransformer, transferring the Wiltshire T2/T7 DESN to Leaside supply defers the needs past the end of the study period for the high electrification forecast, provided up to 150 MW of load rejection between Runnymede TS, Fairbank TS, and Wiltshire T1/T6 is utilized.

The HVDC Third Supply increases available capacity on the Leaside sector and allows for this solution to be implemented. It should be noted that this option would limit the emergency load transfer of Dufferin TS to Manby supply in an emergency event on the Leaside sector. Further studies, including extreme contingency events and their likelihood can inform whether future actions to enhance emergency load transfer capabilities should be explored.

7.6.2.2 Wires Options – Permanent Load Transfer from Fairbank to Downsview

This option involves transferring from 10 MW to 77 MW of load from Fairbank TS to the new Downsview MTS by 2044 (i.e., the same solution proposed in Section 7.6.4). This action would remove this load from the Manby to Wiltshire circuits as Downsview MTS will connect to circuits in northern Toronto. More details on the new Downsview MTS can be found in Section 7.5.

The Technical Working Group acknowledges that transferring load from a transmitter-owned station to an LDC-owned station when station load is below a station's LTR may incur by-pass compensation as per the Transmission System Code. By-pass compensation, in addition to project costs should be examined when comparing wires options in further detail in the Regional Infrastructure Plan.

7.6.2.3 Non-wires Options – Incremental eDSM

The LAPS identified up to 32 MW of incremental eDSM (and behind-the-meter) potential that can be achieved by 2044 in the Manby East area, specifically at Runnymede TS, Fairbank TS, and Wiltshire TS. These incremental eDSM measures pass system cost effectiveness tests, meaning they provide system benefits outweighing their costs.

7.6.2.4 Non-wires Options – Energy Storage Systems

The hourly profile of this need aligns well with the capabilities of a ESS solution. However, the need only emerges towards the later end of the forecast. The Technical Working Group will continue monitoring this need and update the feasibility of ESS in future regional plans.

7.6.2.5 Recommendation to address Manby East Autotransformer needs

The Technical Working Group recommends the following integrated set of options to address the Manby East autotransformer need:

- Continued reliance on Manby RAS
- Permanent Load Transfer from Fairbank TS to the new Downsview MTS
- Incremental eDSM

The above options are recommended as they take advantage of the existing transmission system's operational capabilities and new recommended transmission infrastructure in Northern Toronto through the reliance on existing Manby RAS and permanent transfer of load to Downsview MTS. Incremental eDSM can be targeted as part of the current eDSM framework. A ESS is not recommended at this time, given that it is only needed towards the end of the forecast. A ESS solution can be considered in future regional plans should the load increase more than currently expected.

A summary of the expected costs and lead times for the recommended wires options is provided in Table 16.

Table 16 | Recommended Wires Options to address Manby East Autotransformer Need

Recommendation	Capital Costs ($M CAD)	Lead Time
Reliance on Manby RAS	N/A	Ongoing
Permanent Load Transfer from Fairbank TS to Downsview MTS	To be developed further in upcoming RIP	Less than 3 years (Requires Downsview MTS to be in-service)

7.6.3 Options for Addressing Manby to Riverside Circuits

7.6.3.1 Wires Option – Reconductoring of K13J and K14J from Manby to Riverside

Hydro One first identified the need to upgrade the Manby to Riverside circuits (specifically K13J and K14J) in the 2022 Toronto Needs Assessment Report.[19] Hydro One is currently developing a transmission solution to increase capacity on K13J and K14J to be at least equal to that found on K6J and H2JK circuits. Furthermore, in Energy for Generations,[20] the Ministry of Energy and Mines confirmed support for Hydro One developing this transmission solution.

[19] Hydro One, Needs Assessment Report: Toronto Region, December 2022, https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto_Region_Needs_Assessment_Report_Third_Cycle_Regional_Planning.pdf

[20] Ministry of Energy and Mines, Energy for Generations, July 2025, https://www.ontario.ca/page/energy-generations#section-7

7.6.3.2 Recommendation to address Manby to Riverside Circuits

The Technical Working Group recommends Hydro One continue developing the transmission solution for the Manby to Riverside circuit upgrades in the upcoming RIP. Hydro One estimates that this upgrade will cost $25 million and is expected to be in-service by 2028.

7.6.4 Options for Addressing St Clair to Fairbank Circuits

7.6.4.1 Wires Options – Permanent Load Transfer from Fairbank to Downsview

This option involves transferring between 10 MW and 77 MW of load (reference and high electrification forecasts, respectively) from Fairbank TS to the new Downsview MTS by 2044. This also reduces the loading on the Manby East autotransformers as Downsview MTS will connect to circuits in northern Toronto. More details on the new Downsview MTS can be found in Section 7.5. Transfers should begin by 2036 (i.e., when Fairbank TS demand reaches 179 MW) to respect the current limits of the K1W and K3W circuits.

The Technical Working Group acknowledges that transferring load from a transmitter-owned station to an LDC-owned station when station load is below a station's LTR may incur by-pass compensation as per the Transmission System Code. By-pass compensation, in addition to project costs should be examined when comparing wires options in further detail in the Regional Infrastructure Plan.

7.6.4.2 Recommendation to address St Clair to Fairbank Circuits

The Technical Working Group recommends implementing the load transfer from Fairbank TS to Downsview MTS to alleviate constraints on the St Clair to Fairbank TS circuits. Transfers should be completed by 2036 to respect limits of the K1W and K3W circuits (transfers would need to begin by 2031 to respect the high electrification forecasts).

This cost of this recommended action is included in the Downsview MTS development cost detailed in Section 7.5.2.1. The action is expected to have a lead time of less than three years and requires Downsview MTS to be in-service.

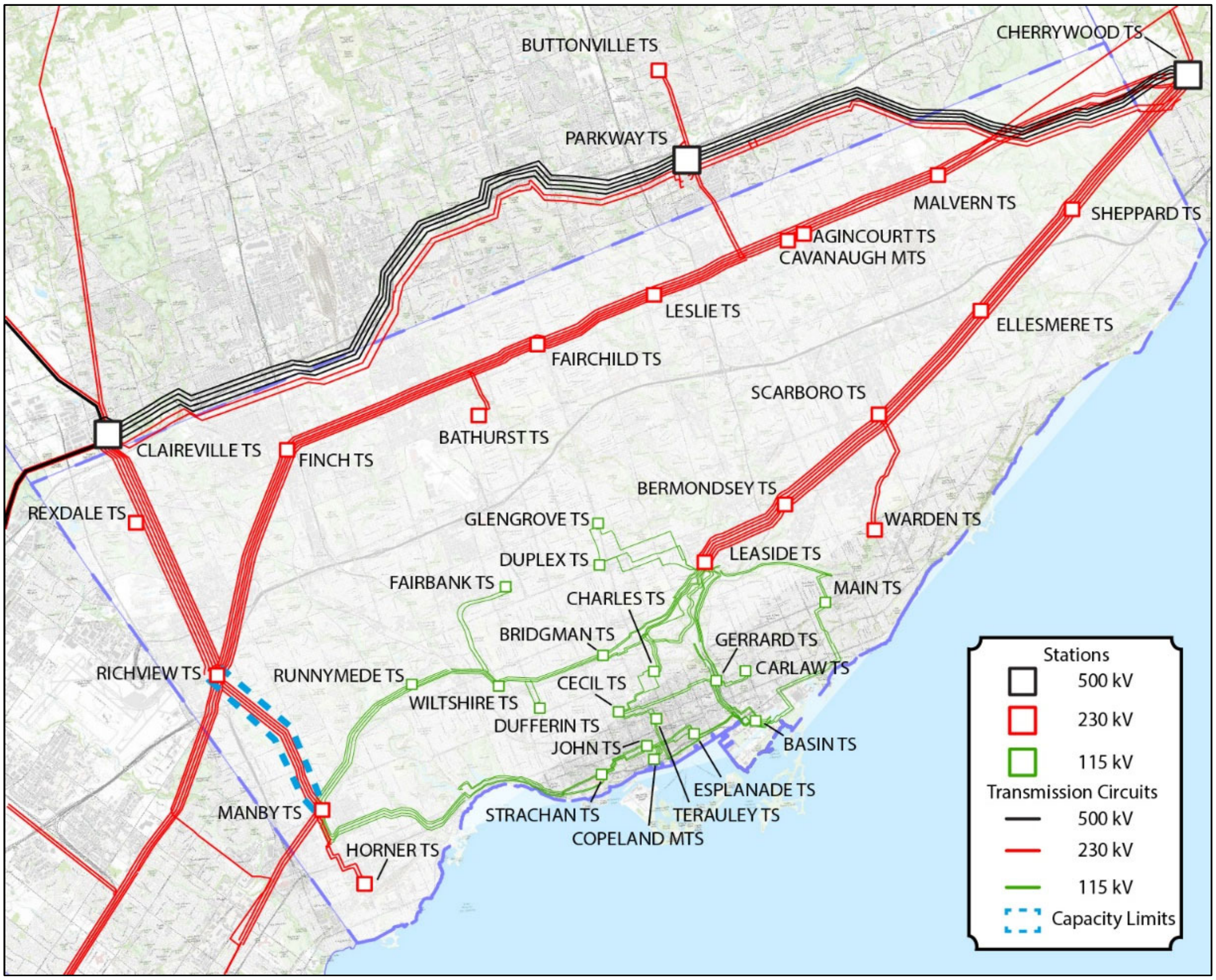
7.6.5 Options for Addressing Richview to Manby Circuits

The Richview to Manby 230 kV circuits supply the western portion of downtown Toronto, Etobicoke, and southern Mississauga (which is part of the GTA West region), as shown in Figure 13. The forecast for the GTA West region, released in May 2025, shows significant load growth especially in southern Mississauga, which will further strain the Richview to Manby circuits. The South and Central Bulk Study is considering wires solutions to meet the needs of both GTA West and Toronto regions. One such solution undergoing evaluation in the South and Central Bulk Study is a 230 kV double circuit line from Trafalgar TS to Oakville TS. This solution will be further explored in the GTA West IRRP where the forecast growth in both GTA West and Toronto regions will be considered. From 2032 in the reference forecast more than 150 MW of load will be required to be shed post contingency to return the loading to below the LTE rating which is a violation of the ORTAC.

Therefore, the Technical Working Group recommends further evaluation of the Trafalgar TS to Oakville TS option continue as part of the South and Central Bulk Study and the GTA West IRRP. The

South and Central Bulk Study and GTA West IRRP expect to publish their findings by Q1 2026 and mid-to-late 2026, respectively.

Figure 13 | Richview to Manby Circuits



7.6.6 Options for Addressing Station Capacity Needs in Western Toronto

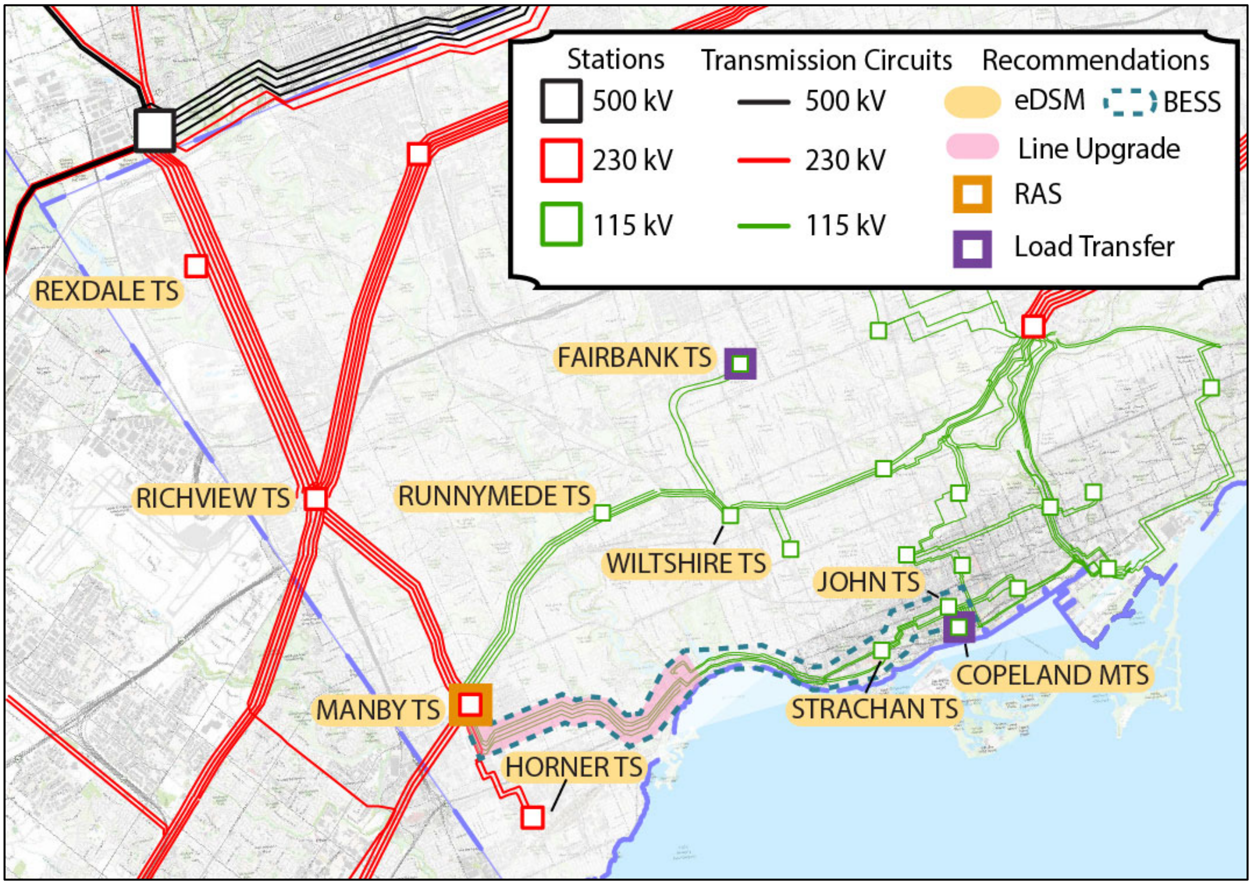
Three stations supplying West Toronto are expected to exceed their station capacity, namely Fairbank TS, Strachan TS, and the Manby DESN. The options identified in the preceding sections will also alleviate the needs at Fairbank TS and Strachan TS. For Fairbank TS, transferring up to 77 MW of load to Downsview MTS to address supply capacity needs will also eliminate the capacity need at the station. Similarly, estimated incremental eDSM at Strachan TS of up to 19 MW by 2040 can defer station capacity needs to the latter part of the forecast. Therefore, the Strachan station capacity need can be further reviewed in the next regional planning cycle.

The needs at Manby DESN occur towards the end of the forecast period, following the asset renewal replacement of the transformers. Since the need isn't expected to occur until 2042 or 2037 under the reference and high electrification forecasts respectively, the Technical Working Group recommends this need be monitored in future regional planning cycles.

This cost of this recommended action is to be developed further in the upcoming Regional Infrastructure Plan. The action is expected to have a lead time of less than three years and requires Downsview MTS to be in-service.

Figure 14 shows the location/connection points of the recommended solutions in Western Toronto

Figure 14 | Recommended Options for Western Toronto



7.7 Options and Recommendations for Eastern Toronto Needs

7.7.1 Options for Addressing Leaside to Bridgman to Dufferin Circuits

7.7.1.1 Wires Option – Increase transmission capacity to Dufferin TS

This option involves upgrading 1.3 km of underground circuits between Dufferin TS and the Bartlett/Dufferin Junctions to a higher capacity (similar ratings to the new C5E and C7E circuits between Terauley TS and Esplanade TS). This option allows for Dufferin TS to be loaded to its station limit (180 MW in summer and 203 MW in winter), as it is currently limited to 135 MW by the transmission supply into Dufferin TS.

7.7.1.2 Wires Option – Permanently transfer Dufferin TS load to expanded Wiltshire TS

This option involves upsizing the T1/T6 transformers at Wiltshire TS to add an additional 62 MW of capacity. This will then allow up to 62 MW of load to be transferred from Dufferin TS to Wiltshire TS. Note that this requires the load transfers from Manby East to Northern Toronto as detailed in Section 7.6.4 to be feasible.

While an upgrade at Wiltshire TS provides the station capacity needed to enable significant load transfers, there are physical limitations based on available underground space in the road allowance and other geographical constraints between the two stations. These limitations make it challenging and expensive to transfer large amounts of load between the stations and will limit how much load can ultimately be transferred.

7.7.1.3 Wires Option – Resolve transmission limits on all lines supplying Dufferin TS

This option involves increasing transmission capacity to Dufferin TS (as seen in Section 7.7.1.1) and from Leaside TS to Bartlett JCT. This will require rebuilding overhead lines including 1.7 km from Leaside TS to Bayview JCT, 2.2 km from Bayview JCT to Birch JCT, and 1.4 km from Birch JCT to Bridgman TS. In addition, a 2.2 km underground section between Bayview JCT to Birch JCT will need to be upgraded.

7.7.1.4 Non-wires Options – Incremental eDSM

The LAPS identified up to 36 MW of incremental eDSM (and behind-the-meter) potential that can be achieved by 2044 in the Leaside to Bridgman to Dufferin area, specifically at Dufferin TS and Bridgman TS. These incremental eDSM activities pass system cost effectiveness tests, meaning they provide system benefits outweighing their cost.

7.7.1.5 Non-wires Options – Energy Storage Systems

The hourly profile of this need aligns well with the capabilities of an energy storage solution[21]. Table 17 shows the minimum capacity and energy build-out requirements, assuming either a single ESS or multiple ESS that are aggregated, to meet the need on an annual basis. Although the ESS will be

[21] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

locally connected, it would serve both the identified regional need and also contribute to provincial resource adequacy. The ESS can be connected to the distribution system or to the transmission system at one of the following locations:

- Dufferin TS (preferred location)
- L13W and L18W (from Dufferin TS to Barlett JCT, must connect to both circuits)

The buildout up to (and including) 2041 meets the need until 2043.

Table 17 | Requirements for ESS to meet Leaside to Bridgman to Dufferin Need

Year	ESS Incremental Capacity Requirements (MW)	ESS Incremental Energy Storage Requirements (MWh)
2037	2	12
2038	4	40
2039	4	37
2040	7	69
2041	24	243
Total	**41**	**401**

This local ESS is expected to have a net system cost of up to $18 million, which accounts for the broader system benefit it enables through a reduction in overall provincial capacity needs. The combination of addressing local and provincial needs, along with using less land, make this option an attractive one for the Leaside to Bridgman to Dufferin need.

7.7.1.6 Recommendation for Leaside to Bridgman to Dufferin Circuits

The Technical Working Group recommends the following options to address the Leaside to Bridgman to Dufferin need:

- Increase transmission capacity to Dufferin TS
- Transfer of Dufferin TS load to upgraded Wiltshire TS
- Energy Storage Systems[22]

To address the upstream supply needs for Dufferin TS the IRRP recommends the cables supplying Dufferin TS be upgraded to fully utilize the capacity available at Dufferin TS. The ratings on the new cables should have similar ratings to the new C5E and C7E cables between Terauley TS and Esplanade TS. Demand in excess of the Dufferin TS station limit can then be transferred to an upgraded Wiltshire TS. These recommendations will be further studied in the upcoming RIP.

A ESS solution capable of meeting the incremental capacity and energy requirements is also recommended to alleviate upstream supply issues (from Leaside TS to Bridgman TS). Given the lead time available for the ESS to be in place, several procurement mechanisms (including future iterations of the IESO's Long-Term procurement) can be used to address both local and provincial

[22] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

supply constraints. The preferred location for ESS, either a large system or multiple smaller systems that are aggregated, is at or downstream (i.e., distribution-connected) from Dufferin TS.

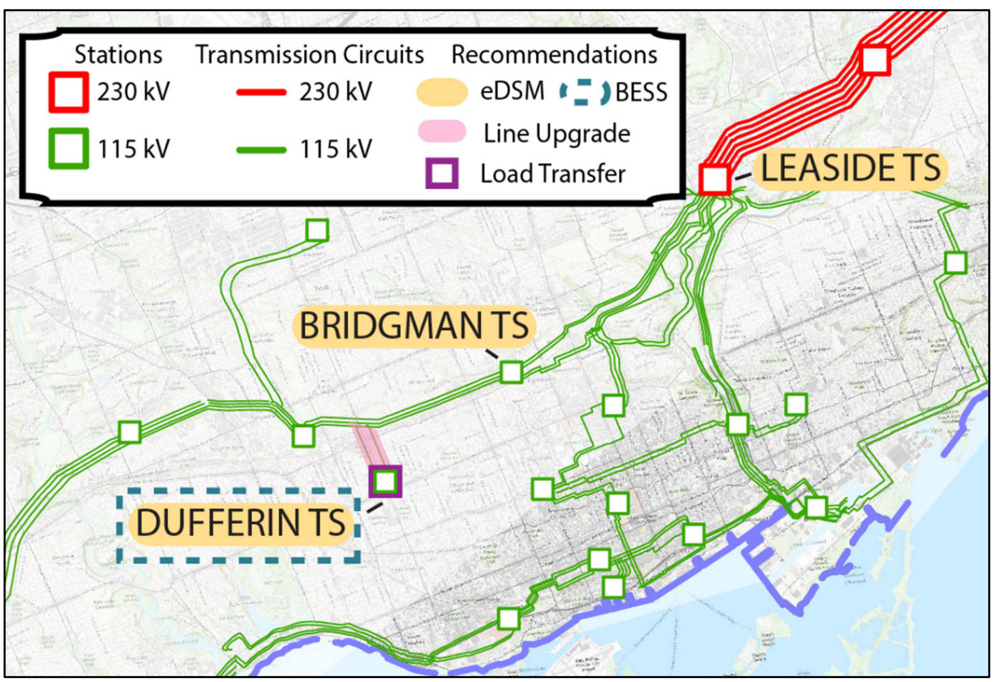
The IESO and Toronto Hydro will need to collaborate to scope the technical requirements, achievable implementation timelines, and decide on the most suitable procurement approaches. The IESO and Toronto Hydro will ensure the Technical Working Group is kept updated on progress and any challenges through annual Technical Working Group meetings.

A summary of the expected costs and lead times for the recommended wires options is provided in Table 18 below.

Table 18 | Recommended Wires Options to address Leaside to Bridgman to Dufferin Circuits

Recommendation	Capital Costs ($M CAD)	Lead Time
Increase transmission capacity to Dufferin TS	33	7 years
Transfer Dufferin TS load to upgraded Wiltshire TS	60	5 years

Figure 15 | Recommended Options for Leaside to Bridgman to Dufferin Area



7.7.2 Options for Addressing Leaside to Bloor to Hearn Circuits

7.7.2.1 Wires Option – Address End-of-Life on circuits from Leaside TS to Bloor JCT

Hydro One identified that the Leaside TS to Bloor JCT sections of the H1L and H3L 115 kV circuits will require asset renewal in the near-term. The IRRP analysis also identified capacity needs on the same sections of the line by 2036. This option is to renew this section of this line, bringing it up to a modern standard and providing an opportunity to increase the capacity limit of the lines.

7.7.2.2 Wires Option – Increase transmission capacity on circuits from Hearn SS to Basin TS

The need on the H1L and H3L circuits from Hearn SS to Basin TS is expected to coincide with the load growth at Basin TS from the expected Port Lands development (2041 and 2037 for reference and high electrification forecasts, respectively). This option involves reconductoring a short span of this 115 kV line (0.5 km) with higher capacity conductors with ratings equal or higher than the new Manby TS to Riverside JCT portion of K13J and K14J.

7.7.2.3 Non-wires Options – Incremental eDSM

The LAPS identified up to 16 MW of incremental eDSM potential that can be achieved by 2044 in the Leaside to Basin to Hearn area, specifically at Carlaw TS, Gerrard TS, and Basin TS. These incremental eDSM measures pass system cost effectiveness tests, meaning they provide both local and provincial system benefits.

7.7.2.4 Recommendation for Leaside to Bloor to Hearn Circuits

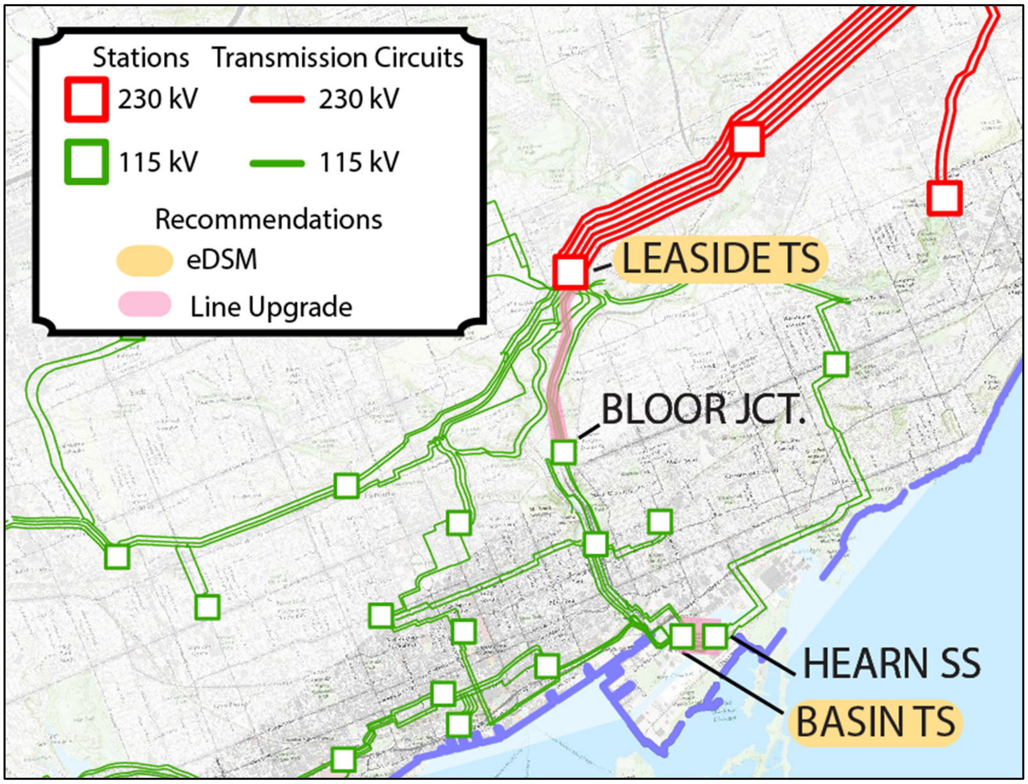
The Technical Working Group recommends that the following options be implemented to address the Leaside to Bloor to Hearn need:

- Increase transmission capacity on H1L and H3L circuits from Leaside TS to Bloor JCT and from Hearn SS to Basin TS.
- Incremental eDSM.

Due to the short span of the Hearn to Basin section (0.5 km) and the end-of-life needs on the Leaside to Bloor circuits, it is recommended that Hydro One investigate reconductoring the aforementioned sections with conductors having ampacity ratings equal to or higher than the new Manby TS to Riverside JCT portion of K13J and K14J. This upgrade will also enable more transfer of power from the Hearn SS and the recommended HVDC Third Supply. Incremental eDSM can help reduce the loading on the circuits, should any delays occur in the replacement of the circuit sections. The locations of transmission facilities from Leaside TS to Bloor, and Hearn SS to Basin TS, are shown in Figure 16.

This recommended wires-option is expected to cost approximately $25 Million and is expected to have a lead time of seven years.

Figure 16 | Recommended Options for Leaside to Bloor to Hearn Area



7.7.3 Options for Addressing Station Capacity Needs in Eastern Toronto

7.7.3.1 Scarboro TS, Warden TS, and Sheppard TS

The needs at Scarboro TS, Warden TS, and Sheppard TS are driven by local growth, specifically the Golden Mile Secondary Plan. As this Secondary Plan involves brand new communities, new transmission and distribution infrastructure will be needed to supply them. In their most recent rates application, Toronto Hydro proposed an additional DESN at Scarboro TS to increase capacity to the area to meet the demand growth from the Golden Mile Secondary Plan. This proposal has been accepted by the OEB.

The new DESN at Scarboro TS would also offload Warden and Sheppard TS, thereby ensuring these stations do not exceed their capacity limits. Over the long-term, a station capacity need at Sheppard TS may still arise. Toronto Hydro has proposed utilizing an unused winding at Sheppard TS to address long-term needs which will continue to be monitored. This recommended action is expected to cost $60 Million and is expected to have a lead time of seven years.

7.7.3.2 Glengrove TS

The need at Glengrove TS occurs in 2042 for the reference forecast and can come up as soon as 2035 in the high electrification scenario. Toronto Hydro identified that there may be opportunity to transfer load from Glengrove TS to Duplex TS. There is also limited opportunity for incremental eDSM (up to 4 MW by 2040) to meaningfully delay any upgrades.

Therefore, the Technical Working Group recommends that Toronto Hydro and Hydro One investigate the feasibility of load transfers from Glengrove TS to Duplex TS in the upcoming RIP. The Technical

Working Group will also continue to monitor load growth at Glengrove TS in upcoming cycles of regional planning.

7.7.3.3 Dufferin TS

The need at Dufferin TS occurs in 2040 for the reference forecast and can come up as soon as 2033 in the high electrification scenario. There is an opportunity to concurrently address station and supply capacity needs by placing the recommended ESS at Dufferin TS. This can defer the need at Dufferin TS to the end of the forecast period. There is some incremental eDSM potential at Dufferin TS (up to 7 MW by 2040) which can further alleviate station capacity needs in the area.

Therefore, the Technical Working Group reiterates the recommendation for the ESS to be connected to Dufferin TS. The Technical Working Group will also continue to monitor load growth at Dufferin TS in upcoming cycles of regional planning.

7.7.3.4 Basin TS

The need at Basin TS is heavily tied to the expected new development at the Port Lands, specifically the developments at Ookwemin Minising and McCleary Districts. The Technical Working Group received a study from the City of Toronto that details the load growth and potential for district energy systems to play an important role in meeting the area’s energy needs. The study shows that district energy can potentially reduce the summer and winter peak demands. Despite this predicted demand reduction, a new station or expanded Basin TS will still be needed to supply new community growth and development in the area.

Therefore, the Technical Working Group recommends Hydro One investigate the feasibility of either expanding Basin TS or adding a new station in the area. With the input of the Technical Working Group, this station should be right-sized to meet the future needs of Basin TS after accounting for the impacts of the planned district energy system in the Port Lands, as well as updated information about the timing and magnitude of development. The City of Toronto will need to continue working closely with Toronto Hydro and Hydro One to finalize the site for a new or expanded Basin TS.

7.8 New Supply Options for Eastern Toronto

7.8.1 Need for Transmission Reinforcement

This need for transmission reinforcement was confirmed by assessing a suite of non-wires alternatives compared to the transmission option. Capacity needs were assessed on an hourly basis for the 20-year IRRP planning horizon and further modeled using an energy production simulation. This approach was taken to understand the timing, magnitude, and duration of peak demands on the existing system, and the total energy requirements to ensure local area reliability. Relying solely on locally sited renewable resources, both standalone and paired with energy storage, as well as a large standalone energy storage system (assumed to be ESS technology), was found to be not feasible to address the total energy need in East Toronto. A significant amount of land area would be required to site these resources at the scale needed to match the size of the need in eastern Toronto.

Other technically feasible local resource options such as utility-scale gas generation and small modular reactors (in combination with ESS) were ruled out due to community preferences and siting challenges. Gas generation would be especially misaligned with the policy position from Toronto City Council. Similarly, incremental eDSM and DERs also cannot fully address the required need. However, both eDSM and DERs can help manage peak demand and, over time, reduce the size of the system need that must be met by other solutions. While these incremental measures could provide some local benefit while a transmission solution is being implemented, findings from the LAPS indicate the achievable potential of these local resources.[23]

While the PEC out-of-service scenario would drive an earlier need date, transmission reinforcement is still required by 2037 to address the capacity need forecasted to emerge in 2038.

Both during the IRRP development and in past transmission plans and studies, the IESO found that due to the built-up nature of the City of Toronto, options for siting new transmission facilities (both lines and stations) are extremely limited. The three possible transmission options studied for the IRRP reflects these limitations. These three options were developed with the objectives of being able to address the local capacity need, while reducing future reliance on PEC for local reliability.

All three options originate from east of the city. They either utilize existing transmission rights-of-way or utilize new paths that minimally impact existing land-uses.

7.8.2 Current Supply Constraints and Future Demand

Downtown Toronto is currently supplied by two transmission corridors: one from the west via Manby TS and one from the east via Leaside TS. A third transmission supply would support future growth and maintain system reliability in the downtown core. This provides an opportunity to address both resilience and capacity needs with a singular solution and was used as one of the considerations when choosing the recommended option for the third transmission line.

7.8.3 Overland Option: Expand 230 kV Leaside TS and New Supply from Cherrywood TS

This option involves expanding the Leaside TS by adding three new 230/115 kV autotransformers at Leaside TS, to complement the existing six, adding six new inline 230 kV circuit breakers between Cherrywood TS and Leaside TS and rebuilding a presently idled overhead transmission line between Cherrywood TS and Leaside TS. There is an idle transmission line along most of the 26 km distance between these two stations. A portion of this line is currently being used by Toronto Hydro for distribution.

This option requires Hydro One to expand the existing Leaside TS by redeveloping adjacent lands available to them starting in 2030,[24] and to rebuild and/or reconductor the existing transmission line structures between Cherrywood TS and Leaside TS. Most of this right-of-way is adjacent to homes, and it transects the Rouge National Urban Park. Some work to re-terminate the existing 230 kV circuits may be required to make this option feasible, as well as upgrades to portions of the 115 kV

[23] Small-scale behind-the-meter resources are not the only tools available for the IESO and Toronto Hydro to manage local demand and maintain local reliability. Larger, front-of-the-meter (FTM) generation resources can participate in ongoing and future IESO procurements; and the IESO is developing a Local Generation Program targeting smaller-scale FTM resources. There are also mitigation measures available in the operational timeframe, such as new and expanded Remedial Action Schemes, to manage a range of reliability risks. These types of measures are often deployed as interim measures while grid reinforcements are being planned or implemented.

[24] Pers. Comm. From Hydro One to the Technical Working Group.

transmission system between Leaside TS and Hearn SS. These 115 kV lines are aging, and upgrade work could be timed to coincide with the work needed to refurbish these facilities at their end-of-life.

7.8.4 Overland and Underground Option: Build a New 230 kV Transformer Station Downtown Supplied from Cherrywood TS

This option involves adding two 230/115 kV autotransformers at Hearn SS and building a double circuit 230 kV line between Cherrywood TS and Hearn SS by rebuilding about two-thirds of the existing idle line between Cherrywood TS and Scarboro TS. This option also requires reinforcing or expanding the existing overhead 230 kV transmission line from Scarboro TS to Warden TS, extending a new 230 kV line from Warden TS a further 3 km to Lumsden Junction, and finally constructing new underground 230 kV cables approximately 9 km to Hearn SS in the Port Lands. This option will require additional inline breakers on the Cherrywood TS to Leaside TS circuits, between Scarboro TS and Leaside TS, and additional 230 kV reconfiguration work between Scarboro TS and Warden TS to re-terminate existing circuits. This option would also allow the retirement of approximately 7 km of 115 kV cable sections of H7L and H11L between Hearn SS and Main TS.

7.8.5 Underwater Option: New HVDC Transmission Supplying Downtown from the East

The third option considered is a new high-voltage direct current (HVDC) link into the Port Lands in downtown Toronto from the bulk transmission network east of Toronto. Two potential points of origin were considered for this option where there is existing transmission infrastructure with available capacity east of Toronto near the Lake Ontario shoreline (Bowmanville SS and Pickering). Both high voltage alternating current (AC) and HVDC technologies were considered in the analysis.

Bowmanville SS was selected as the preferred point of origin because injecting bulk supply into Toronto from this location delivers additional benefits for the bulk network by bypassing Cherrywood TS altogether and freeing up additional capacity at the station to supply growth elsewhere in the Greater Toronto Area (GTA). HVDC technology was chosen over AC because it offers additional benefits and ancillary services, and becomes more cost-effective than AC for submarine cable lengths greater than approximately 50 km. The IESO has carried out a preliminary land review and assessed there is undeveloped land available to accommodate HVDC converter stations near the Bowmanville SS and the Hearn SS.

This HVDC Option involves installing approximately 65 km of submarine HVDC cables underneath Lake Ontario. Horizontal directional drilling is a common approach to make the transition from land to water while minimizing surface and sediment disruption. Voltage-source converter (VSC) stations, a key component to HVDC transmission, are a mature technology that continues to improve in key areas such as losses and compactness of the station footprint. A VSC station would need to be sited and constructed at each terminal end. Some additional work on the 115 kV system in the Port Lands in Toronto will be required to accommodate a higher power injection as compared to the injection through PEC, and inline breakers will need to be added to the Cherrywood TS to Leaside TS 230 kV transmission circuits to add further resiliency to the current supply to East Toronto.

7.9 Third Supply Options Analysis

To arrive at a recommendation, the IESO received information from the IRRP Technical Working Group, including exploratory cost estimates and preliminary project scope information for the overland and overland and underground transmission options. The IESO consulted with the transmission development community to obtain additional information for submarine HVDC technologies. These discussions focused on underwater HVDC facilities built in the last ten to 15 years and covered technical aspects of project planning, construction, operation and maintenance, environmental challenges and project economics. This research, extensive engagement, and the IESO's system studies have informed the detailed evaluation of the three transmission options summarized in this section.

The planning considerations factored into the assessment of the transmission options are introduced below, and each is summarized in the sub-sections that follow.

- **Reliability performance –** Ability to supply Toronto's future demand in accordance with the established reliability criteria for electric power systems, without reliance on PEC.
- **System resilience** – Impact on the power system's ability to withstand or recover from major events such as a loss of Manby TS or Leaside TS, and the flexibility to support a range of possible futures.
- **Bulk power system impact –** Benefits for the upstream bulk transmission network.
- **Implementation complexity –** Impacts on land-use and ability to manage potential risks throughout development and implementation of the option.
- **Cost-effectiveness for ratepayers –** cost effectiveness of the option in providing power reliably and safely to consumers.

7.9.1 Reliability Performance

7.9.1.1 Load Meeting Capability

The performance of each transmission option was studied in terms of its ability to supply Toronto's forecasted electrical demand. Each option provides a substantial increase in load meeting capability in Toronto and can meet the identified supply capacity needs.

The HVDC Option was shown to provide the largest increase to the system's load meeting capability. With the inclusion of incremental eDSM and/or local DERs, an integrated solution comprising the HVDC line and additional local measures can also meet needs driven by the high electrification forecast. In addition to offloading the transformers at Leaside TS, a capacity injection at Hearn SS would also offload the transmission system further upstream including the transformers at Cherrywood TS.

By comparison, the Leaside TS expansion option provides enough incremental new capacity to defer these system needs to 2042; and the combined overhead and underground option to the Port Lands can defer these system needs to 2044 under the reference case forecast. These options would require additional eDSM and/or DERs to meet these needs further into the future and additional transmission reinforcement would be required sooner to equal the additional load meeting capability of the HVDC Option.

7.9.1.2 Ancillary Services – Voltage Control

The VSC station technology that accompanies the implementation of an HVDC transmission line can provide specific reliability benefits through dynamic reactive power, providing voltage control and maintaining energy flows independent of power system conditions. Voltage control is critical in reducing risk of voltage collapse that could result in blackouts on a local or system-wide level. Specifically, in this case, the location of a VSC station near the Hearn SS is expected to provide reactive power support where it is needed within the load centre, and near Bowmanville SS, close to the Darlington Nuclear complex. This benefit is expected be quantified in further studies of the option as part of the detailed design process. Even if the underwater cable portion is out of service, the VSC stations can operate in STATCOM mode to continue to regulate voltage and support grid stability.

Reducing reliance on PEC also means losing the voltage support capabilities currently provided by the facility. HVDC with VSC technology can provide this voltage support. Neither of the AC options can provide this service.

7.9.2 System Resilience Benefits

7.9.2.1 Supply Diversity

The theme of resilience has consistently been raised by stakeholders as an objective of electricity planning. This reflects local concerns about climate change, aging infrastructure, and the impact of major events like the loss of Manby TS supply due to flooding that occurred in July 2024 and previously in July 2013. The three transmission options were reviewed in terms of their ability to deliver improved system resilience. While system resilience itself is not easily measured, incremental improvement to resilience is partly a function of the diversity of supply to an area, and the degree to which the different sources of supply can support each other during system outages.

The root of this issue is the reliance of Toronto's dense urban centre on two radial 230 kV transmission paths, Manby TS and Leaside TS, each with limited ability to back up the other. Leaside TS is reliant on a single radial 230 kV supply path from Cherrywood TS. A loss of Leaside TS can interrupt supply to half of the central 115 kV system, and a loss of Cherrywood TS can interrupt supply to this area plus a large part of the remaining eastern half of the city including East York and a significant portion of Scarborough.

The HVDC Option would bring a new, geographically and electrically separated source of supply directly into the urban centre. It has the capacity to replace PEC as a local source of supply, while adding redundancy in the event of transmission outages. Major events such as the 2024 flooding event at Manby TS that disconnected about 900 MW of load, and the similar 2013 event that disconnected about 3,800 MW of load impacted hundreds of thousands of customers. Toronto has experienced at least three 1-in-100-year rainfall events since 2005, and, due to the aging network and increasing frequency of extreme weather, both planned maintenance and the likelihood of unplanned outages are expected to increase into the future. If an event of a similar magnitude to the two Manby TS outages interrupted supply from Leaside TS for an eight-hour period, the economic consequences could be in the order of $400 million.[25]

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[25] Based on an assumed load interruption of 900 MW for an eight-hour period, using a Value of Lost Load calculator recommended in the Ontario Energy Board's Vulnerability Assessment & System Hardening Report.

A new diversified supply source can provide better continuity of supply and better load restoration capability in East Toronto during and/or after major events, should one impact supply from Leaside TS or Cherrywood TS. Additionally, with minimal upgrades to the 115 kV system connecting the Manby TS (western) and Leaside TS (eastern) sectors, the supply to a large portion of the financial district in Downtown Toronto could be transferred to the new third supply source. This would extend the reliability benefits from East Toronto into the western Toronto Manby TS sector. These benefits include reducing the loading on Manby TS, and potentially deferring other future system upgrades needed to ensure reliability.

Lastly, as the HVDC cables would be submerged, they will be more immune to the effects of extreme weather compared to overhead transmission.

The Leaside TS expansion option does not provide the same level of system resilience benefit that a true third point of supply to the downtown can provide. Like the HVDC Option, with additional 115 kV system reinforcements, an expanded Leaside TS could facilitate increased load transfers from Leaside TS to Manby TS and provide some co-benefits for the Manby TS sector. The combined overhead and underground option to the Port Lands also provides some of the same benefits for reliability and system resilience. However, this option results in the East Toronto supply remaining reliant on supply from Cherrywood TS, and potentially vulnerable to major events impacting Cherrywood TS and multi-element contingencies impacting the Cherrywood TS to Leaside TS transmission corridor.

7.9.2.2 Operational Flexibility

The power flows across HVDC transmission systems are highly controllable, as the technology allows grid operators to dial the flow up or down, in either direction, across the line independent from the interconnected AC grid. This operational flexibility is beneficial under normal operation as demand in Toronto fluctuates through the day, as well as during periods of maintenance and/or outages on other parts of the local 115 kV transmission system.

Neither of the AC transmission options allows for comparable level of controllability, and therefore neither option provides system operators an equivalent level of real-time operational flexibility. In addition, because of this bi-directional control, the HVDC Option provides flexibility over a longer timeframe, making it compatible with a range of possible futures. For example, functioning as a transmission infeed to the city, the line benefits a future Toronto in which the city remains at a supply deficit and maintains a strong reliance on the interconnected grid for local electricity supply. Conversely, if a long-term future scenario unfolds with high penetration of local DERs (including storage), the flows across the HVDC line could be reversed to export power to the provincial grid.

HVDC technology contributes very little to fault current levels on the surrounding AC transmission system.[26] High fault current levels have been a limiting factor on the amount of DERs that can be integrated into Toronto's legacy 115 kV system, and while actions have been undertaken over many years to increase equipment ratings, this issue persists today. As HVDC lines and converter stations contribute very little fault current compared to AC transmission and synchronous generators (such as

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[26] "Fault current" refers to extremely high magnitude of current that flows through a circuit during a fault, such as a short circuit or a line to ground fault. These fault currents can be significantly higher than the normal operating current of the system, and must be managed within the capabilities of the equipment to avoid causing severe damage to equipment and disrupting power supply.

PEC), the HVDC Option can contribute to alleviating technical barriers to higher DER penetration rates in the City of Toronto. These benefits will be evaluated through subsequent planning and short circuit studies and through preliminary project scoping and development.

7.9.2.3 Ancillary Services – Black-start Capability

Black start refers to the process of re-energizing a power system following a full or partial outage event without requiring additional power from the grid. In the case of a high impact, low probability event (e.g., complete loss of Leaside supply), power can be restored to the city through the HVDC cable. It therefore can play a critical part in improving restoration times in the event of a loss of supply from other sources.

Neither of the AC options can provide this service, and this is not a service that PEC currently provides. For the HVDC Option to provide this service, it would need to be intentionally scoped into the project design and built into the cost.

7.9.3 Bulk Power System Impact

7.9.3.1 Benefit to Cherrywood TS and 500 kV Network

Only the HVDC Option that originates to the east of Toronto can provide benefits to the bulk power system in addition to the Toronto local area. Cherrywood TS is the main bulk point of supply into the Eastern Toronto system, and it also acts as a critical bulk supply hub interconnecting Pickering Nuclear Generation and linking the GTA to Eastern Ontario. It is already one of the most heavily loaded bulk stations in the GTA. As the HVDC Option would bypass Cherrywood TS by providing a new path into the downtown core, it can reduce bulk congestion and defer the forecasted need to increase transformation capacity at the station. It may also defer or avoid the need for new 500 kV transmission from Cherrywood TS to Parkway TS in addition to additional 500 kV transformation capacity. This frees up the existing bulk transmission assets to supply additional load growth not only in Toronto but also in the Regions of Durham and York and surrounding areas. And by alleviating congestion on the bulk system east of Toronto, the new supply path into the load centre can also allow more generation to connect in the east, which is currently limited due to limitations on the current transmission interface governing power flows from east to west in the GTA.

The full scope of these bulk system benefits is being assessed as part of the South and Central Bulk Study and will continue to be assessed in subsequent bulk studies. If a 500 kV station and/or new 500 kV lines can be avoided, the ratepayer savings could be in the order of $100 million to $300 million or more (this preliminary estimate will be refined in subsequent studies). Neither of the AC options can provide similar benefits to the broader provincial bulk transmission network outside of the Toronto local area.

7.9.4 Implementation Complexity

7.9.4.1 Land-use Impacts

As the HVDC Option is expected to be built under Lake Ontario, with HVDC converter stations enclosed in buildings sited on presently vacant land and/or former industrial sites, it has the least land-use impact among the three options. All options will require a similar amount of land area for stations. The IESO learned through engaging with HVDC transmission system owner-operators that horizontal directional drilling is a common method of making the land-water transition, which would have no surface impact beyond the construction phase. As compared to the AC options, less coordination to navigate through built-up areas would be required during construction and for routine maintenance or repair. Horizontal directional drilling, as an alternative to trenching methods, can avoid disturbing contaminated near-shore sediments in Toronto's inner harbour and is a method that has been successfully used in Lake Ontario.[27]

Both AC options would require construction through heavily built-up urban areas and would disturb existing secondary uses (e.g., community gardens, recreation, active transportation corridors). A significant amount of effort and investment has been made in the Meadoway project on portions of the existing Gatineau transmission corridor from Cherrywood TS. This corridor also crosses the Rouge National Urban Park. Delays may occur to manage the reconfiguration and outages of multiple key circuits supplying East Toronto as would be expected for any construction within the existing Cherrywood TS to Leaside TS corridor.

7.9.4.2 Project Development Challenges

The underwater HVDC transmission line would be the first of its kind in Ontario. There will be challenges associated with the novelty of the technology and its application as an underwater cable. Key project development steps including environmental and regulatory approvals and permitting, including provincial and federal environmental assessments. Environmental assessments may be coordinated so that a single environmental assessment meets the legal requirements of both jurisdictions.[28]

Through engagements, the IESO learned that there is a wealth of worldwide experience building similar projects and interest in developing transmission systems in Ontario. HVDC technology is the most common means of interconnecting offshore wind projects to the electricity grid and for building interties between jurisdictions over various distances up to hundreds of kilometers apart. Several similar projects are in the presently under construction worldwide. The IESO is confident, based on this growing volume of experience planning and executing similar projects, that implementation challenges can be effectively managed.

HVDC technology is currently in high demand, and there are a limited number of original equipment manufacturers (OEMs) that are commercially producing cables and VSC station components. The IESO learned that there are factory production queues for equipment, and due to bespoke nature of HVDC technology solutions, it is advantageous for developers to secure their slots in the production queue as early as possible. Once in a queue, production timelines can be three to four years (current estimate, as of August 2025), during which time the developer can continue to proceed with obtaining the various approvals and permits. For Toronto's third supply, there is time to meet the in-service date as long as implementation, concurrent with further community engagement and project scoping, continues without significant delay following the IRRP publication.

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[27] For example, the pipe connecting to Hydrostor's compressed air energy storage pilot was installed by directionally drilling approximately 1 km into Lake Ontario at depths up to 45m deep.

[28] Canadian Environmental Assessment Act, 2012. Requests must be made formally and approved by the federal Minister. Separate provincial and federal decisions are still required for the substituted process.

7.9.5 Cost Effectiveness

7.9.5.1 Cost of the Three Options

All three transmission options are major infrastructure investments, and all are estimated to cost in the order of $1 billion to $1.5 billion. The HVDC Option, based on a combination of sources, is estimated to cost approximately $1.5 billion, with a range of uncertainty equivalent to a Class 5 "exploratory" cost estimate.[29] The final cost will depend largely on the specific technical and design attributes of the project. For example, a bipole line will cost more than a symmetrical monopole line,[30] while offering a higher level of redundancy in the event of a cable fault.

Hydro One provided preliminary cost estimates for the AC alternatives which indicate that these options have a lesser upfront capital cost than the HVDC Option. Hydro One also indicated that these estimates are preliminary and lack defined uncertainty ranges.

As the HVDC and the two AC options have very different performance attributes and deliver different benefits both for Toronto customers and provincial ratepayers, it is not appropriate to select the preferred option based on the initial cost alone. At the same time, many of the additional benefits the HVDC Option provides are challenging to express quantitatively, including the provision of voltage support, operational flexibility, compatibility with a range of uncertain futures, potential for black-start capability, and land-use impacts. The bulk system benefit to ratepayers of the HVDC Option could be several hundred million dollars, which alone brings the cost of HVDC much closer to the other two options. And while extreme weather-related major events are still relatively rare, occurring about once per decade, the resilience benefit of the HVDC Option for reducing the impact and improving restoration following these events is significant. On balance, the IESO is confident the underwater HVDC Option provides positive benefits to ratepayers and the community, relative to the understood costs.

7.9.5.2 Realizing the Value of Long-term Transmission Investments

Over the last 20 years, while making investments in Toronto's 115 kV system, Hydro One has taken advantage of opportunities to upgrade 115 kV transmission equipment to a 230 kV design standard. For example, the John TS to Esplanade TS underground cable, the cable replacements between Riverside Junction and Strachan TS, and the Terauley TS to Esplanade TS underground cable (presently under construction) have all been built to a 230 kV standard. These enabling investments were undertaken to work toward a future operating voltage conversion from 115 kV to 230 kV in parts of the downtown core.

The HVDC Option preserves the optionality to convert parts of the downtown transmission system to 230 kV operation. The combined overland and underground option terminating in the Port Lands would also provides this potential benefit, but the overland option that reinforces the supply via Leaside TS does not.

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[29] Expected accuracy range from a low of -20% to -50% to a high of +30% to +100%. This is an industry standard estimate of the typical low and high ranges based on the maturity level of the project definition. The expected accuracy narrows as the project scope is further defined in the later stages of project development.

[30] HVDC systems can be configured as monopole (one conductor with ground or sea return) or bipole (two conductors, positive and negative). Bipole usually offers better reliability.

7.9.6 Recommended New Supply for Eastern Toronto

The IESO's recommendation for the preferred third transmission option is the underwater HVDC Option. This option addresses the long-term supply capacity need in East Toronto that exists with or without PEC in-service. When interconnected with the bulk transmission network at Bowmanville SS, it also delivers broader bulk system benefits. The HVDC technology provides additional reliability and resilience benefits to Toronto, including:

- Accommodating the highest incremental demand growth among the three options,
- Improved supply diversity and system resilience by introducing a true third supply path into the downtown core,
- Bulk reinforcement, deferral, enables system resources east of Toronto
- Ability to control power flows independent of conditions on the rest of the IESO-controlled grid,
- Additional ancillary services such as voltage control and black-start capability (e.g., ability to restore power following a local blackout), and
- Improved system performance and load restoration following major events beyond the normal planning criteria for the electric power system (e.g., events such as a complete loss of Manby TS[31] or Leaside TS).

The proposed connection points of the HVDC Option are shown for illustrative purposes in Figure 17. The project developer would be responsible for leading the design, undertaking route studies, establishing the route, seeking approvals, and constructing the facilities.

[31] Examples of such events include the July 2013 and July 2024 floods that both led to loss of Manby TS supply.

Figure 17 | Illustrative Map of the Toronto Area Showing the HVDC Option

Table 19 provides a summary of all three options for a new supply to Toronto.

Table 19 | Summary of Three New Supply Options to Toronto

	Option 1: Overhead	Option 2: Overhead + Underground	Option 3: Underwater (Recommended Option)
Estimated Capital Cost	$800 million	$900 million	$1.5 billion
Avoided Bulk System Reinforcements	N/A	N/A	Up to $300 million[32]
Year of Growth Enabled	2042	2044	Beyond 2044 (past the IRRP study timeline)
Load Meeting Capability (MW)	3,350	3,400	>3,400
$/MW Capacity Enabled	$1.5 million[33]	$1.5 million	$1.7 million[34]

32 Preliminary estimate – the bulk system benefits are being evaluated in the South and Central Bulk Study.
33 Includes preliminary cost estimate of bulk system reinforcements avoided by the HVDC Option.
34 Does not consider the value of other local system benefits, including voltage support, black-start capability, or improved system resilience.

	Option 1: Overhead	Option 2: Overhead + Underground	Option 3: Underwater (Recommended Option)
System Resilience	Similar to today: two supply points	Moderate improvement: new supply to downtown, still reliant on Cherrywood TS	Significant improvement: new supply from a separate bulk connection
Other System Benefits	None	None	Local voltage support Relieves Cherrywood TS Enables more generation to connect in eastern Ontario
Other Development Considerations	Proximity to housing Potential conflict with Meadoway secondary land-use on corridor and Rouge National Urban Park	Underground facilities through built-up areas technically challenging; feasibility not certain	Bespoke equipment with production queues Lack of Ontario transmitter experience building HVDC and long underwater systems

7.9.7 Compatibility with Large ESS in the Port Lands

The IESO's technical studies found that injecting more than 900 MW at the Hearn site can contribute to thermal exceedances on parts of the 115 kV system under certain conditions. This presents challenges with co-locating additional transmission-connected resources (such as a large ESS[35]) in the same location as the HVDC Option. This creates a potential congestion issue when the transmission system is injecting into this location at the same time the ESS is discharging into the system. Therefore, with the HVDC Option, siting a large ESS connected to the Hearn SS may not be technically and economically feasible in the long-term. A smaller size energy storage system may be feasible. The Toronto IRRP has identified other suitable location for ESS, as noted in Sections 7.6.1.5 and 7.7.1.5.

7.9.8 Addressing Resilience of Toronto's Electricity System

7.9.8.1 Increasing Resilience through the HVDC Option

The recommended HVDC option will increase the diversity of supply to downtown Toronto in addition to enabling demand growth over the next 20 years. One of the most significant contributions of the HVDC option to system resilience is the introduction of a third, geographically and electrically distinct supply path into Toronto's urban core. Currently, the city relies heavily on two radial 230 kV transmission paths, Manby TS and Leaside TS, both of which have limited ability to provide emergency supply should one suffer a complete loss of supply. This configuration has proven vulnerable during extreme weather events, such as the 2013 and 2024 floods that disrupted supply from Manby TS, affecting hundreds of thousands of customers. During these events, the limited

[35] All technical energy storage assumptions in this report assume the use of lithium-ion battery technology.

ability to resupply Manby TS from Leaside TS, even with PEC in-service, impacted the duration and severity of the outage.

The HVDC line bypasses Cherrywood TS and injects power directly into the downtown core via Hearn SS. This reduces dependency on the Cherrywood to Leaside corridor, mitigating the risk of cascading failures, and ensures continuity of supply during outages or emergencies for customers in eastern Toronto. It also improves the ability for the City's eastern supply to accommodate loads supplied by Manby TS should a loss of supply event occur in the western Toronto area. In effect, this third point of supply will enable faster restoration of service in the event of major outages.

Increasing frequency of extreme weather events pose serious risks to the electricity system. The HVDC cables, being submerged under Lake Ontario, are inherently more resilient to surface-level disruptions such as wind, ice storms, and flooding. This physical separation from urban infrastructure and environmental hazards significantly lowers the risk of damage, making the system more robust in the face of climate change.

HVDC technology also offers additional operational flexibility. Unlike AC systems, HVDC allows grid operators to control power flows independently of the rest of the grid. This controllability is crucial for managing fluctuating demand, scheduling maintenance, and responding to both planned and unplanned outages. Additionally, the HVDC system can be designed to include black-start capability, allowing it to re-energize the grid after a complete outage without relying on external power sources. This feature is not available in the existing AC options or through PEC, making HVDC a critical asset for emergency restoration and system recovery.

7.9.8.2 Climate Vulnerability Study

To account for climate risk in future system planning studies of Toronto's electricity system, the IESO will undertake a desktop study of climate vulnerabilities as part of ongoing planning. This study will assess climate change-related risks at key points of the electricity system across Toronto. The study is intended to equip planners with insights to determine the scope of extreme contingencies to be assessed in future studies.

The study will involve a comprehensive GIS-based analysis of historical and projected climate data including temperature, precipitation, and flooding trends. It will incorporate data from sources such as Environment and Climate Change Canada, the Climate Atlas of Canada, and regional conservation authorities. By modeling future scenarios under different emissions pathway scenarios, the study will also help planners anticipate how climate risks may evolve over time and affect system performance.

This information is particularly valuable for the IRRP process, which seeks to balance reliability, cost-effectiveness, and resilience. For example, insights from this study can inform decisions about where to prioritize upgrades, reinforce vulnerable assets, or deploy non-wires alternatives like DERs and energy storage. It can also support transmission planning, such as the proposed HVDC line to downtown Toronto, by identifying climate-resilient routing options and station siting considerations.

Moreover, the study's emphasis on visual mapping and trend analysis enhances transparency and engagement. It enables planners, municipalities, and Indigenous communities to better understand the risks and participate meaningfully in shaping resilient energy solutions.

In summary, this climate vulnerability study will provide the IESO with a data-driven foundation for carrying out subsequent planning studies to strengthen Toronto's electricity system against future climate impacts. It ensures that regional plans are informed by localized risk assessments, enabling proactive, resilient, and adaptive infrastructure planning for a rapidly changing environment.

7.9.8.3 Extreme Contingencies Assessment

Extreme contingencies are high-impact, low-frequency events that could severely disrupt Toronto's electricity supply. Studies of this nature involve identifying system vulnerabilities and mitigating measures to address the risk of extreme contingencies. The recommendations in this IRRP, as described in this report, will help mitigate the risk of some extreme contingencies, but the outlook for demand growth and threat of extreme weather events will likely cause new system vulnerabilities to emerge. Therefore, the IESO will work with Toronto Hydro and Hydro One to assess the scope and timing of an updated extreme contingencies assessment. The results of this work will inform future regional planning cycles. The results of an extreme contingencies assessment are not typically made public because they can contain detailed information about system vulnerabilities that could pose security risks if disclosed.

8 South and Central Bulk Study

IESO is currently undertaking a bulk system study focused on the Southwestern and Central regions of Ontario, particularly along the Windsor to Hamilton corridor as well as the urban centers in the GTA.

The driver of the South and Central Bulk Study is to support economic growth in Southwestern Ontario and the GTA and enable new supply resources by:

- Confirming the transmission reinforcements required to enable connection of the small modular reactor (SMR) project at Darlington Nuclear Generating Station and expanded nuclear supply at Bruce.
- Determining the transmission upgrades needed to allow decreased reliance on emitting resources at York Energy Center in the York region, PEC in Toronto, Halton Hills generating station in GTA west and Sithe Goreway generating station in Brampton.
- Determining the transmission needed to enable reliable supply in high growth and economic development areas including the GTA and the Windsor to Hamilton corridor.
- Identifying new corridors required for future transmission reinforcements.

The Bulk Study has been carried out in coordination with the Toronto IRRP to integrate options to enable growth in the city and deliver new supply. Some of the key linkages from the bulk study to this IRRP are as follows:

- The buildout of a new double circuit 500 kV line from Bowmanville SS west towards the GTA will enable the connection of the SMR project and increase supply from Eastern Ontario towards the GTA and Southwestern Ontario. This reinforcement from the east will help redistribute load between heavily utilized GTA bulk stations at Cherrywood, Parkway and Claireville which currently supply Toronto along with York and Durham Regions and the western GTA.
- The HVDC third supply to Toronto is also expected to have bulk impacts as it will be another major supply from the east towards the city, providing an alternate independent route to meet the city’s growing demand. The feasibility of this option was considered at both the regional and bulk system level. The Bulk Study also examined how the third supply to Toronto would impact how and where the required 500 kV reinforcement from Bowmanville gets terminated in the GTA.

The South and Central Bulk Study will be published in early 2026.

9 Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to Indigenous communities, market participants, municipalities, stakeholders, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the Toronto IRRP.

9.1 Engagement Principles

The IESO's External Relations Engagement Framework and Indigenous Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 18 | The IESO's Engagement Principles

9.2 Engagement Tactics

To ensure that the Plan reflects the needs of Indigenous communities, municipalities, stakeholders, communities, market participants, customers and the general public, engagement involved:

- Leveraging the Toronto engagement webpage to post updated information, engagement opportunities, webinar materials, feedback received and the IESO response to feedback, as well as supplementary data and information.
- Targeted one-on-one discussions with Indigenous communities and the City of Toronto to help inform the engagement approach and to ensure that the communities' identified needs are considered.
- Hosted a series of public webinars at major milestones in the development of the plan to share details, understand feedback and answer questions.
- Communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.
- A new PoweringGTA.ca website sharing details of active electricity plans within the GTA, including Toronto.
- Social media content on the IESO's LinkedIn and Instagram accounts to increase awareness of the planning efforts underway.

9.3 Engagement Approach

The engagement for the Toronto IRRP provided valuable insights into the local drivers and pockets of growth, priorities for the City of Toronto, community preferences, and the community vision for the future of Toronto. These insights shaped the development of the Plan and informed an integrated regional resource plan for the City of Toronto that is best suited to meet Toronto's unique and growing needs.

The IESO led an engagement strategy that included targeted one-on-one discussions with the City of Toronto and Indigenous communities, hosted technical briefings with communities as well as 6 public webinars to share information and solicit written feedback from interested rights holders and stakeholders. The purpose of each engagement opportunity was to build awareness and education of the regional planning process, provide updates and information pursuant to the Plan's development, and enable informed and meaningful community and stakeholder feedback. Outcomes of targeted community discussions and stakeholder feedback helped to inform and guide the development of the Plan at each key milestone.

To support the analysis of non-wire options, the IESO retained a consultant to develop a Local Achievable Potential Study (LAPS) to identify opportunities for incremental energy savings through energy efficiency, behind-the-meter distributed energy resources, and demand response. Engagement for the LAPS was included as part of the Toronto IRRP engagement approach.

Public webinars received high registration and were attended by a diverse group of interested stakeholders including the City of Toronto, Indigenous communities, government, industry, environmental associations, and community organizations. Written feedback was invited following each webinar. The six milestones of engagement, and which point feedback was invited, included:

1. Draft scoping outcome assessment report to share the planning approach before commencing the full IRRP study
2. Draft IRRP engagement plan, and draft electricity demand forecast for the region
3. Identified electricity needs for the region and introduction of the Local Achievable Potential Study
4. Results of the options screening for wire and non-wire options to meet the identified needs
5. Draft results for the Local Achievable Potential Study
6. Analysis of options and draft IRRP recommendations

Overarching themes of feedback heard during the development of the IRRP primarily focused on:

- Phase-out of PEC, and avoid new gas generation
- Community preference for non-wire options to meet electricity needs
- Enhanced transparency for data/information and decision-making rationale
- Alignment with City of Toronto decarbonization initiatives such as TransformTO
- Recognition of the need for a third supply line; coupled with requests for more information on the evaluation of options, impacts of routing options, and concern it would bring nuclear energy into the city

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations. A summary of the engagement milestones is described below.

9.3.1 Scoping Assessment

The IESO held preliminary discussions with the City of Toronto to help inform the engagement approach for the third round of planning, and to strengthen relationships and dialogue in this region that would inform the development of the Plan at each milestone. Engagement started with the draft Scoping Assessment Outcome Report for the Toronto Region. An invitation was sent to the City of Toronto, Indigenous communities, other stakeholders, and to the Toronto subscription list to announce the commencement of a new planning cycle and invite interested parties to provide input on the draft Toronto Region Scoping Assessment Outcome Report. A public webinar was held on February 16, 2023, to provide an overview of the regional electricity planning process and the scoping assessment, and to seek input. The final Scoping Assessment Outcome Report was posted on March 21, 2023, identifying the need for a coordinated regional planning approach through the development of an IRRP.

The key themes of feedback received during the scoping assessment milestone included study considerations for modelling extreme weather events, coordination with third party electricity demand studies (i.e., Port Lands DER study), opportunities to facilitate DERs, inclusion of a diversified electric and low-carbon gas scenario, and coordination with institutional customers to factor in their electrification plans into the regional forecast. The IESO considered this feedback in the development of the plan and posted its response to the Toronto engagement website.

9.3.2 Demand Forecast

Following the finalization of the Scoping Assessment, the Technical Working Group began the development of Toronto’s electricity demand forecast. IRRP recommendations are typically driven by the reference demand forecast, which includes firm loads (current and planned), organic growth, residential, electrification and energy plans, and development plans. The Technical Working Group also developed a high electrification scenario to test potential demand growth that is less certain, assuming higher electrification adoption rates. The IESO sought input from the City of Toronto to identify drivers and pockets of growth, decarbonization and electrification initiatives.

To enable meaningful feedback and promote transparency, the IESO publicly posted a detailed forecasting methodology document and load forecast data tables to the engagement website early in the engagement process for stakeholder consideration. On April 16, 2024, the IESO hosted a public webinar to share the draft reference and high electrification scenarios, drivers of growth, draft engagement plan, and to seek stakeholder feedback. Feedback was received from 20 stakeholders, ranging from requests for information on methodology, requests for specific data and assumptions, inquiries on alignment with City of Toronto net zero plans, and requests that non-wires be considered in the Plan's development. Feedback on the draft engagement plan included enhanced collaboration with Indigenous communities and stakeholders throughout the planning process to produce better outcomes. The IESO considered this feedback in the development of the plan and posted its response to the Toronto engagement website.

9.3.3 Electricity Needs

During this milestone, the IESO identified that the growing demand for electricity is causing significant electricity infrastructure needs across the western, northern, and eastern parts of the city. The IESO hosted a public webinar on December 5, 2024, to share the specific station and supply capacity needs in each area, detailing that a mix of large-scale wire and non-wire solutions would be required to meet the growing demand. The IESO further shared that reducing reliance on PEC amid growing demand for electricity would introduce large capacity needs.

During the webinar, the Local Achievable Potential Study (LAPS) was introduced to stakeholders as a tool to inform the non-wire analysis milestone in the Plan. The IESO shared the scope, methodology, and data inputs of the LAPS, and requested feedback from stakeholders.

The IESO received feedback from 21 stakeholders on the electricity needs and the LAPS methodology and scope. Feedback at this stage included additional requests for improved transparency of the demand forecast, support for the scenario without PEC, recommendations to close the facility, consideration of non-wires options to meet needs (including reconsidering offshore wind as an option), and feedback for the LAPS scope and methodology. The IESO considered this feedback in the development of the plan and posted its response to the Toronto engagement website.

9.3.4 Options Screening

During this milestone, the IESO completed the options screening for the wire and non-wire solutions to meet needs across the city. The IESO hosted a public webinar on July 10, 2025, to share the screening criteria, and outcomes of the screening process for each need. Generally, wire options were screened-in as a solution to meet the needs, and non-wire options were screened-in in combination with wire options. The IESO also shared the three potential options for the third supply line in the webinar. The IESO collected written feedback and received 30 feedback submissions.

Feedback on the options screening included continued advocacy that non-wire solutions should play a key role in the Plan, and requests for more information on the analysis of the non-wire solutions including land-use requirements and capacity. The IESO also heard that alignment of the Plan with decarbonization initiatives such as TransformTO and phase out of PEC with a committed timeline was important to many stakeholders.

Feedback specific to the third supply line demonstrated general support for the need for the third transmission supply line. City of Toronto staff shared general support for the transmission expansion and emphasized accelerating DER deployment for a future without PEC, the need for transparent route selection and stakeholder engagement, and minimizing land disruption and aligning with redevelopment priorities. Additional themes of feedback for the third supply line centered on concerns for prioritizing nuclear resources over the potential for renewable generation and impacts to lands and habitats. Feedback from Indigenous communities include concerns about potential impacts to environmental and archaeological sites, including along the shorelines. Technical briefings were provided to Indigenous communities to help address environmental concerns.

The IESO considered this feedback in the development of the plan and posted its response to the Toronto engagement website.

9.3.5 Draft Results Local Achievable Potential Study

To further enhance and supplement the regional planning work underway for Toronto, the IESO conducted a local eDSM achievable potential (LAPS) study with consultant ICF International. The purpose of the study was to identify and quantify electricity energy savings potential, electricity 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. To inform the development of the study, the IESO held a dedicated public webinar to share the draft results of the study and seek feedback.

The IESO received 11 feedback submissions from interested stakeholders. Key themes of feedback included:

- Opinion that customer program participation assumptions were too conservative
- Interest in district energy systems and front-of-the-meter wind, solar and energy storage (note that these front-of-meter resources have been considered in the Toronto IRRP but outside the LAPS reflecting the LAPS focus on customer-sited behind-the-meter resources).
- Inclusion of local health, economic and climate benefits of additional eDSM investments in the LAPS' cost-effectiveness analysis
- Comparison of draft results previous IESO-procured achievable potential studies and potential estimates of other parties
- Exclusion of vehicle-to-grid/building measures in the study

The IESO considered this feedback as part of the finalization of the Study, including in updates to customer program participation assumptions. The IESO addressed the exclusion of vehicle-to-grid/building measures in a separate memo posted with the draft results to the Toronto engagement website.

9.3.6 Options Analysis and Draft Recommendations

The final stage of engagement included the details of the options analysis and the draft recommendations for the Plan. The IESO hosted a public webinar on September 25, 2025 that provided an update on the Local Achievable Potential Study, shared details of the options analysis (including technical feasibility, ability to meet the need, cost, lead time, and other considerations), and the draft recommendations for each need in the west, north, and eastern parts of the City. The IESO also provided the details of the comparative analysis for each option for the third supply line, and the rationale for the preferred option in this final webinar.

The IESO made great efforts to release all publicly available information and data at key milestones for both the regional plan and the Local Achievable Potential Study to support the engagement process. To assist stakeholders in referencing all the available information, the IESO posted a Toronto Regional Plan Information Package in advance of this webinar, which can be viewed here.

The IESO received 15 feedback submissions on the options analysis and draft recommendations for the IRRP, including the preferred option for the third supply line. General feedback themes included the perspective that the IRRP showed a priority and overreliance on transmission infrastructure over non-wire options, desire for an electricity plan that sought to align with City of Toronto climate initiatives (including the phase out of PEC), support for draft recommendations to use load rebalancing opportunities, ESS, and eDSM where possible, and finally recommendations for implementation pathways for DERs and TENs. The City of Toronto commended the IESO for its transparent planning process and its commitment to modernizing regional energy planning by incorporating municipal input and evaluating innovative solutions like non-wires alternatives, demand-side management, and energy storage in the IRRP. Many stakeholders thanked the IESO for its efforts and due diligence in creating a comprehensive electricity plan.

Feedback on the third supply line included support for the need for the line and the value it will bring to the city. Stakeholders were interested to understand how the third supply line could support decarbonization efforts, such as helping to phase out PEC sooner and connecting to renewable generation outside the city. Some stakeholders shared concerns that the third supply line was prioritizing nuclear energy and untested SMR technology, and the source of nuclear was not in the interest of Canadians at this time.

9.4 Involving Municipalities in the Plan

The IESO engaged early and often with the City of Toronto to ensure that key local information about growth and development, energy-related plans, and environmental initiatives were taken into consideration in the development of this IRRP. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships and build trust, and provided opportunities for ongoing dialogue beyond this IRRP process. Additionally, the IESO led council outreach that included letters prepared for mayors and councillors, and one-on-one councillor meetings to provide elected officials with updates on electricity planning developments, and to provide an opportunity for discussion.

Through these discussions valuable feedback was received around growth and community preferences around solutions informing the IRRP, including:

- City of Toronto shared the drivers of load growth and pockets of high growth (i.e., TransformTO, Electric Vehicle Strategy, Secondary Plans, Green Bus Program, City of Toronto Official Plan) to be factored into the demand forecast scenarios and help to identify local needs and opportunities.
- The Technical Working Group leveraged ongoing City of Toronto studies into the IRRP (i.e., Downsview Airport site, Port Lands, Golden Mile Plan, electricity demand studies, and distributed energy resource analysis).
- City initiatives to decarbonize were contemplated at many levels, including for example, TransformTO and other electrification initiatives factored in the demand forecast. In response to the City Council request to align IRRP with City's 2040 target of net zero emissions the IESO included a scenario to understand timing and options for a future without PEC, and the IESO studied the ability of non-wire options to meet electricity needs.
- City perspectives on routing and siting of infrastructure for the third supply line that align with City plans, such as Port Lands redevelopment plans and potential for complementary energy storage.

9.5 Engaging with Indigenous Communities

To raise awareness and share information about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to the following Indigenous communities:

- **Mississaugas of the Credit First Nation**
  Toronto is situated within the lands covered by Treaty 13, signed with the Mississaugas of the Credit First Nation.
- **Alderville First Nation**
- **Beausoleil First Nation**
- **Chippewas of Georgina Island First Nation**
- **Chippewas of Rama First Nation**
- **Curve Lake First Nation**
- **Hiawatha First Nation**
- **Mississaugas of Scugog Island First Nation**
  The preceding seven communities are signatories to the Williams Treaties, which cover parts of the Toronto region. The Mississaugas of Scugog Island First Nation is a Williams Treaties First Nations member inclusive of the "Gunshot Treaty", which covers the north shore of Lake Ontario, beginning at the eastern boundary of the Toronto Purchase, within the City of Toronto.
- **Six Nations of the Grand River**
  The community is represented by the Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council.
- **Métis Nation of Ontario**

The IESO remains committed to an ongoing, meaningful dialogue with communities to help shape long-term planning in regions across Ontario. This engagement was part of a broader commitment to fostering respectful relationships, ensuring transparency, and supporting informed participation in regional energy planning. Throughout the development of this plan, the IESO's engagement with

Indigenous communities included extending the opportunity to meet one-on-one to address any inquiries or concerns about the IRRP, and the third supply option discussed in Section 7.8 specifically.

9.5.1 Indigenous Engagement Feedback

The following summarizes feedback received in writing and verbal communications with Indigenous communities. Feedback submitted to the IESO can be viewed on the Regional Electricity Planning - Toronto engagement webpage.

Mississaugas of the Credit First Nation (MCFN)

The IESO met with the Mississaugas of the Credit First Nation (MCFN) to provide an overview of the Toronto IRRP, including the region's electricity needs and the three supply line options under consideration. In addition to being treaty rights holders of land within the Toronto region under Treaty 13, the MCFN communicated that they submitted an aboriginal title claim to the water and waterbeds of Lake Ontario. The community has requested that Ontario pause review of that claim. This information may be relevant to the underwater transmission option (Option 3) as discussed in Section 7.8 (New Supply Options for Eastern Ontario), if pursued. The MCFN expressed interest in better understanding the potential environmental and archeological impacts of the underwater transmission option as well as the emergency repair and remediation options available. The MCFN have requested additional information and/or studies to support their review and feedback.

Mississaugas of Scugog Island First Nation (MSIFN)

The Mississaugas of Scugog Island First Nation (MSIFN) expressed a commitment to collaborative solutions that support reliable energy, honour their rights, and foster prosperity for the community. The MSIFN provided feedback on the proposed investments and recommendations contained in the IRRP, with a focus on the underwater transmission option (Option 3) as discussed in Section 7.8 (New Supply Options for Eastern Ontario). In particular, the MSIFN identified land and environmental concerns about the underwater transmission option, if pursued. The MSIFN also expressed an interest in ongoing participation and engagement in the regional planning process.

Hiawatha First Nation

The Hiawatha First Nation communicated concerns with environmental and archaeological sites, including along the shorelines, in a one-on-one meeting discussion. This information may be relevant to the underwater transmission option (Option 3) as discussed in Section 7.8 (New Supply Options for Eastern Ontario), if pursued.

Six Nations of the Grand River (SNGR)

The IESO met with Six Nations of the Grand River (SNGR) to present the Toronto IRRP, outlining the region's electricity needs and the three supply line options under review. SNGR expressed interest in remaining engaged in the IRRP process but did not provide feedback at this time.

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