GTA North (York Region) Integrated Regional Resource Plan

October 10, 2025

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List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CDM	Conservation and Demand Management
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
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
RIP	Regional Infrastructure Plan
TG	Transmission-connected Generation
TS	Transformer Station
TWG	Technical Working Group

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Executive Summary

The GTA North (York Region) Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the GTA North Region over a 20-year period, from 2024 to 2043. The GTA North Region is located in southern Ontario and is defined by electrical infrastructure boundaries, not municipal, yet roughly includes the municipalities of Aurora, East Gwillimbury, Georgina, King, Markham, Newmarket, Richmond Hill, Vaughan, Whitchurch-Stouffville, and parts of Simcoe County, including Bradford-West Gwillimbury. Because these municipalities primarily fall within York Region, the terms "GTA North Region" and "York Region" are used interchangeably in this study.

For the purposes of this IRRP, the region is often divided into four electrical subsystems: Northern York, Kleinburg, Southern Vaughan-Richmond Hill, and Markham and Area. 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 and other coordinated planning efforts, including regional planning in GTA West and South Georgian Bay-Muskoka, and corridor identification and preservation initiatives.

The Region of York is growing rapidly, with a population of 1.26 million in 2024, and is expected to grow to over 2 million by 2051. Existing infrastructure supplying York Region is insufficient to meet anticipated growth in electricity demand. Some sections of northern York in particular are already experiencing challenges in connecting new customer loads. Investing in new transmission infrastructure would have a positive impact on the region, especially increasing the ability for new loads to connect, and maintaining the reliability of existing customers throughout York Region.

The electricity demand forecast for York Region shows significant growth over the planning horizon, driven by residential intensification, commercial development (including large energy-intensive customers), and electrification trends (such as electric vehicles and heat pumps). Summer peak demand is expected to nearly double by 2043, while winter peaks could potentially triple depending on the pace of electrification. While the region has historically been summer-peaking, winter peaks could become more limiting by the early-2030s. Given the uncertainty associated with long-term growth forecasts, particularly with respect to winter peaks that rely on new customer behaviour and technological availability, this study has placed a greater emphasis on managing uncertainty and risk in demand forecasts. In practice, only summer peak forecasts have been used to make recommendations which require immediate action. For longer term needs, dates associated with summer peaks have been the primary driver for planning during this cycle. The impacts of higher potential winter peaks have been considered and will continue to be monitored through the Annual Working Group to determine the need to trigger long term system reinforcements.

To identify near-, medium-, and long-term needs, the Technical Working Group 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 near-term needs. Options for addressing longer-term needs are also proposed, but do not yet require action, except to preserve long-term viability of the solution options. Non-wires alternatives (NWAs) such as targeted electricity demand-side management (eDSM) and distributed energy resources

(DERs) have been recommended to help manage near-term reliability risks and potentially defer longer-term infrastructure requirements.

Additional consideration has also been given to long term impacts of reduced reliance on York Energy Centre, following its contract expiry in 2035. This includes evaluation of the impact of the loss of supply on the local system, and potential solutions which may need to be pursued if this facility is no longer available.

The study has also considered points of coordination with an ongoing bulk planning initiative, 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 in 2026 with a focus on bulk system needs into the 2040s, will similarly consider potential impact of bulk enhancements on regional supply. Both studies have the potential to affect longer-term needs and feasibility of solutions available to in the area, particularly for needs emerging post 2035 or 2040.

Engagement was a key component of this IRRP. The IESO engaged with municipalities, Indigenous communities, stakeholders, and the public throughout the planning process. 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

Near-term recommendations emerging from this plan will provide increased station and system capacity across the region and allow for anticipated load growth to be reliably met into the 2030s. Immediate action is recommended to implement the following:

Table 1| Summary of Near-Term Recommendations

Project	Need	Need Timing	Expected In-Service
Additional targeted incremental eDSM to manage demand and ease pressure on the system	Station and Supply Capacity in Northern York, Markham, Richmond Hill, and Whitchurch-Stouffville	Ongoing	Ongoing
Reconfigure York Energy Centre Station Service Supply	Supply Capacity in Northern York	Immediate	2026
Develop Northern York TS #1	Station Capacity in Northern York	Immediate	2030
Develop Markham MTS #5	Station Capacity in Markham	2029	2028/2029

Project	Need	Need Timing	Expected In-Service
Develop Richmond Hill MTS #3	Station Capacity in Richmond Hill	2030	2030
Install new breakers along Parkway to Claireville corridor	Load Security in Vaughan and Richmond Hill	Immediate	2028/2029
Reconductor Circuit P45/46 from Parkway to Buttonville TS to support Markham TS #5 (in phases)	Supply Capacity in Markham	2029	2029
Build a new 230kV transmission line along the future Highway 413 corridor (Kleinburg – Kirby Transmission Line)	Supply Capacity in Northern York	2030	2031/2032
Develop/preserve viability of long-term capacity options through corridor identification and preservation initiatives	Station and Supply Capacity	Ongoing	Ongoing

The Technical Working Group will continue to monitor and may recommend action based on revised forecasts and demand growth for these medium- to long-term needs and recommendations:

Table 2| Summary of Medium- to Long Term Recommendations

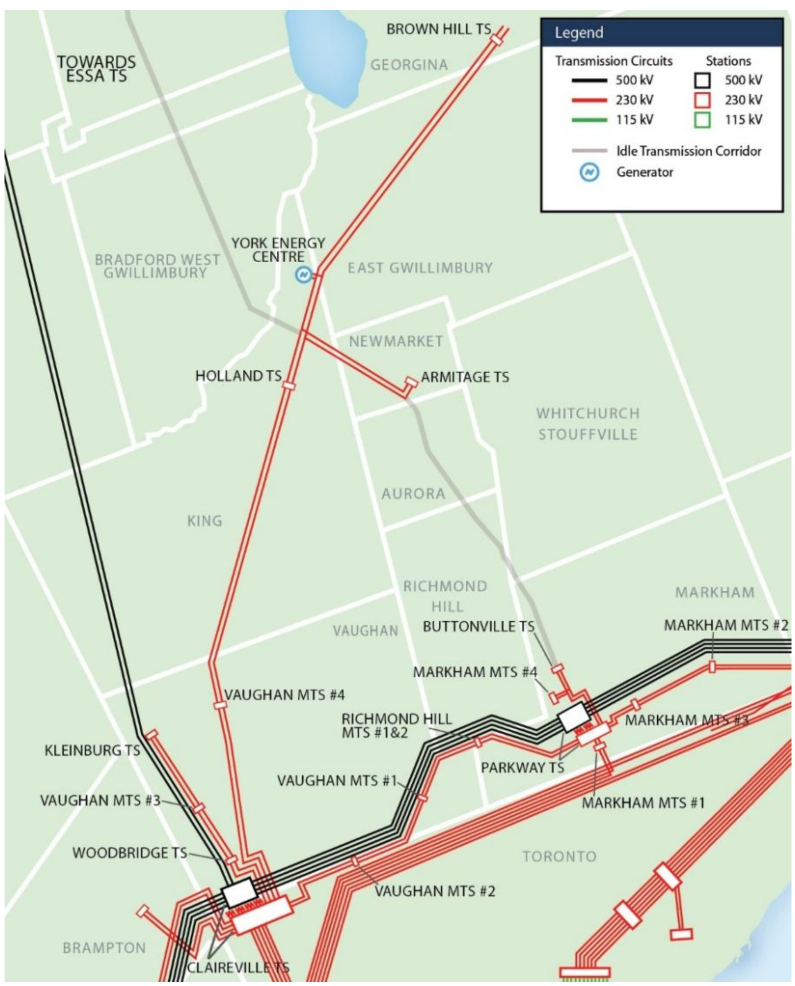
Project	Need	Need Timing	Expected In-Service
Develop Vaughan MTS #5	Station Capacity in Vaughan	2033	2033
Extend transmission from Buttonville TS and develop Northern York TS #2 and Markham TS #6	Station Capacity in Markham, Richmond Hill, and Whitchurch-Stouffville	2034	2034
Monitor future electricity needs and begin early planning for new infrastructure including Northern York TS #3 and the Holland switching station	Station and Supply Capacity in Northern York	2035	2035

1 Introduction

This Integrated Regional Resource Plan (IRRP) addresses electricity needs for the GTA North Regional Planning area ("GTA North" or "York Region") between 2025 and 2043. This report was prepared by the Independent Electricity System Operator (IESO) on behalf of the York Region Technical Working Group comprising the IESO, Alectra Utilities Corporation (Alectra), Newmarket-Tay Power Distribution Ltd. (NT Power), Hydro One Networks Inc. (Hydro One Distribution), and Hydro One Networks Inc. (Hydro One Transmission).

In Ontario, planning to meet the electrical supply and reliability needs of a local area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, at least once every five years. The GTA North Region, shown in Figure 1, roughly corresponds with the municipal boundaries of York Region. For the purposes of this plan, GTA North and York Region can be used interchangeably.

Figure 1| Overview of the GTA North (York) Region



Development of the GTA North (York Region) IRRP was initiated in October 2023, following the publication of the Needs Assessment report in July 2023 by Hydro One and the Scoping Assessment Outcome Report in October 2023 by the IESO. The Scoping Assessment identified the area's needs should be further assessed through an IRRP. The Technical Working Group was then formed to gather data, identify near-, medium-, and long-term needs in the region, and develop the recommended actions included in this IRRP.

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 background for electricity planning in the region and the study scope is discussed in Section 4
- The development of the demand forecast, including 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
- Linkages to the South and Central Bulk Study is outlined Section 8
- A summary of engagement activities is provided in Section 9, and
- The conclusion is provided in Section 10.

2 The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of York 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) and Northeast Power Coordinating Council (NPCC). The IRRP's recommendations are informed by an evaluation of different options to address the region's needs in consideration of reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from communities and stakeholders.

2.1 Status of Projects from Previous IRRP Cycles

Following the previous cycle of regional planning, which concluded with the 2nd Cycle RIP report, several projects were recommended that have now been completed or are presently underway. The status of these projects is summarized in Table 3.

Table 3 | Needs Identified in the Previous Cycle with Revised In-Service Date

Project	Need	Expected In-Service
Collect Information on future NWAs and opportunities in York Region to inform the next IRRP	Station and Supply Capacity	Ongoing
Reconfigure York Energy Centre Station Service Supply	Supply Capacity	2026
Develop Markham MTS #5	Station Capacity	Expected in Service Date in 2028/2029
Reconductor Circuit P45/46 from Parkway to Markham MTS #4	Supply Capacity	Expected in Service Date in 2029
Develop Northern York TS #1	Station Capacity	Expected in Service Date in 2030
Develop/Preserve Viability of Long-term Capacity Options	Station and Supply Capacity	Ongoing

2.2 Plan for Near-Term Needs (2026-2030)

The near-term plan consists of several recommendations to enable load growth and maintain reliability. Many of these needs are immediate, and based on today's peak demand, while others are based on strong anticipated load growth over the next five years. Implementation should be initiated immediately to ensure required in service dates can be met.

Additional targeted incremental eDSM to manage demand and ease pressure on the system. As an interim measure, eDSM may be considered to manage shortfalls where the infrastructure solution is not expected to be in service in time to meet existing or anticipated needs. eDSM also has the potential to defer the need for additional infrastructure investments anticipated to be required in the medium- to long-term.

Reconfigure York Energy Centre (YEC) Station Service Supply. Upgrading the station supply arrangement for YEC would allow for this facility to remain operational for a wider range of transmission outage conditions. This would have an immediate reliability benefit for local customers and improve the ability to supply load in the area. Cost and in-service timelines will be evaluated following more detailed site-specific analysis.

Develop Northern York TS #1. The need for additional station capacity in Northern York is immediate. Based on existing loads and near-term demand forecast, it is recommended that Hydro One proceed with the acquisition of land, the design, and the construction of a new step-down station by 2029 to serve Northern York Region, in the vicinity the Holland TS area. Typical development costs for these types of stations, including real estate, are generally $60 million.

Develop Markham TS #5. The need for additional station capacity for Markham area was identified in the previous IRRP and reaffirmed with the latest demand forecast to be required by 2029. Alectra has identified a suitable location for the next Markham MTS #5 near the existing Buttonville TS on the P45/46 circuits, and this project is currently under development. Typical development costs for these types of stations, including real estate, are generally $60 million.

Develop Richmond Hill MTS #3. The need for additional station capacity in Richmond Hill is expected by 2030, triggered by new development applications in proximity to the planned Yonge subway extension. Alectra has identified a suitable location for the next Richmond Hill MTS #3, and this project is currently under development. The proposed connection point will be along the V71/75V circuits, near the existing Richmond Hill MTS #1 and #2. Typical development costs for these types of stations, including real estate, are generally $60 million.

Install new breakers along Parkway to Claireville corridor. The existing V71/75P transmission corridor between Claireville TS and Parkway TS are currently loaded at over 600 MW during summer peak, with demand having exceeded 730 MW in 2025. This violates applicable security criteria, and loading is expected to worsen following the connection and loading of Richmond Hill MTS #3 in 2030 and Vaughan MTS #5 in 2033. Estimated costs are $30-35 million.

Reconductor Circuit P45/46 from Parkway to Buttonville TS to support Markham TS #5. Connection and loading of the new Markham MTS #5 is expected to trigger thermal needs on P45/46. Reconductoring of the existing lines will enable full loading of this station, which comes into service in 2028/2029. The cost of reconductoring the entire facility is estimated at $14, though there are opportunities to carry out this work on a phased basis.

Build a new 230kV transmission line along the future Highway 413 corridor (Kleinburg – Kirby Transmission Line). A new, six-km double circuit 230kV transmission line is proposed adjacent to the planned Highway 413 in Vaughan. This new transmission line, referred to as the Kleinburg – Kirby Transmission Link, would create a connection between the existing Kleinburg radial tap, and connect to a point north of the exiting Vaughan MTS #4 along the H82/83V circuits. It would enable the connection and full loading of the next Northern York TS #1 step down station. The cost of this transmission is estimated at $40 million, with an estimated in-service date of 2031-2032. Operation of this facility will require coordination with bulk system upgrades at Kleinburg TS, as under development in the ongoing Bulk System Plan for South & Central Ontario (see Section 8).

2.3 Plan for Medium to Long-Term Needs (2031-2040)

While most recommended actions from this plan are concerned with addressing near term needs (within the next five years), the sections below outline potential medium- to long-term recommendations beyond that horizon. These recommendations, including their targeted in-service dates, are subject to change and will be continuously re-evaluated as planning progresses, based on new information and actual load growth. Early identification of these plans is important to ensure ongoing engagement with potentially affected communities, coordination with broader regional and bulk system planning, and to enable timely implementation when required. It is recommended that the Working Group finalize a long-term adaptive pathway[1] for each subsystem following the completion of this cycle of regional planning.

Develop Vaughan MTS #5. The need for additional station capacity in downtown Vaughan is expected in 2033, triggered by intensified development in the Vaughan Metropolitan Centre (VMC). Alectra is in the process of evaluating potential locations for the next Vaughan MTS #5. The ultimate connection point will likely be along the V71/75V circuits, between the existing Vaughan MTS #1 and the Richmond Hill MTSs. Typical development costs for these types of stations, including real estate, are generally $60 million.

Extend transmission from Buttonville TS and develop Northern York TS #2 and Markham TS #6. The need for additional station capacity in the areas of northern Markham, northern Richmond Hill, and Whitchurch-Stouffville is expected to trigger the need for the development of two new step-down stations, Markham MTS #6 and Northern York TS #2, in the mid 2030s. In order to supply these stations, an approximate 7-km extension of the existing P45/46 circuits is recommended into northern Markham, along an existing, idle transmission right of way. Costs of this transmission could range from $45 million to $175 million, depending on the technology selected during the project scoping and environmental assessment process (e.g., overhead versus underground). This solution would also require development of a new transmission tap to remove Markham MTS #4 from P45/46 supply. The preferred location to supply this station would be the C35/36P circuits, with a likely additional cost of $9 million.

[1] Adaptation pathways are sequences of actions, which can be implemented progressively, depending on future dynamics and uncertain variables.

Monitor future electricity needs in northern York and begin early planning for new infrastructure including Northern York TS #3 and the Holland switching station. Longer-term station capacity needs will likely trigger additional transmission upgrades in Northern York including, at a minimum, a new switching station in the vicinity of Holland Marsh junction to coincide with the development of Northern York TS #3 in the mid 2030s. Switching stations typically cost $200-250 million, though it would also have bulk system benefits. The potential retirement of York Energy Centre post-2035 has also been identified as a key driver of future supply needs and would likely trigger the development of additional infrastructure in the area. The exact nature of options and recommendations will continue to be evaluated and will be informed by ongoing bulk system studies.

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 local area – defined by common electricity supply infrastructure – over the near, medium, and long term periods. The result is a plan aimed at ensuring 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 recommends actions.

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 proposes recommendations to meet the identified needs requiring coordinated planning; 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. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

3.2 GTA North IRRP Development

The process to develop the GTA North (York) Region IRRP was initiated in October 2023, following the publications of the Needs Assessment Report in July 2023 by Hydro One and the Scoping Assessment Outcome Report in October 2023 by the IESO. The Scoping Assessment recommended that the needs identified for GTA North 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.

4 Background and Study Scope

This is the third cycle of regional planning for the GTA North (York) Region. This Region is located in southern Ontario and includes all or part of the following cities, towns and townships:

Aurora	Bradford West Gwillimbury	East Gwillimbury	Georgina
King	Markham	Newmarket	Richmond Hill
Simcoe County	Vaughan	Whitchurch-Stouffville	

For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries. This Region also includes several Indigenous communities that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land use:

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, 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, Métis Nation of Ontario.

Following a Needs Assessment in March 2018 and a Scoping Assessment in August 2018, an IRRP and subsequent RIP were initiated and published in February 2020 and October 2020, concluding the second planning cycle for the Region.

This IRRP develops and recommends options to meet the electricity needs of the GTA North (York) 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 energy resources (DERs) transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

The GTA North (York) Region covers a large portion of the transmission system in both the Toronto and Essa IESO electrical zones. As all the transmission facilities in the region are included in the scope of this study, it has often been broken up into four subsystems:

- **Northern York Subsystem (B88H/B89H, H82V/H83V) Subsystem**

  This subsystem consists of five step-down transformer stations that supply northern Vaughan and communities in Northern York Region (Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina and the Chippewas of Georgina Island). York Energy Centre is connected to these 230 kV circuits. This subsystem also serves as a pathway for power to flow between northern and southern Ontario.

- **Kleinburg (V44/V43) Subsystem**

  This subsystem consists of three step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon, as well as some areas of Brampton, Mississauga, and Toronto. Power is delivered into this subsystem from Claireville TS.

- **Southern Vaughan-Richmond Hill Subsystem (V75P/V71P, P21R/P22R)**

  This subsystem consists of four step-down transformer stations that supply the southern parts of urban communities in the Markham, Richmond Hill and Vaughan areas.

- **Markham and Area Subsystem (P45/P46, C35P/C36P)**

  This subsystem consists of 6 step-down transformer stations that are located in urban communities primarily in the Markham. This subsystem also serves as a pathway for power to flow across the GTA along the Parkway Belt/Highway 407 transmission corridor.

The Northern York subsystem consists of the following stations:

Brown Hill TS	Armitage TS	Holland TS	Vaughan MTS #4

The Kleinburg subsystem consists of the following stations:

Kleinburg TS	Vaughan MTS #3	Woodbridge TS

The Southern Vaughan-Richmond Hill subsystem consists of the following stations:

Vaughan MTS #1	Vaughan MTS #2	Richmond Hill MTS #1	Richmond Hill MTS #2

The Markham and Area subsystem consists of the following stations:

Buttonville TS	Markham MTS #1	Markham MTS #2	Markham MTS #3	Markham MTS #4

The GTA North (York) IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over the 2024-2043 timeframe (as described in Section 5);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, taking into account facility ratings and the performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying the criteria and standards from ORTAC, NPCC, and NERC.
- 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 LDCs.

- 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 eDSM.
- Engaging with the community on needs and possible alternatives.
- Evaluating alternatives to address near-, medium-, and long-term needs; and 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 GTA North (York) Region. It highlights the assumptions made for peak demand forecasts, including weather correction, and the contribution of eDSM and DG. The LDCs in the region provided both a winter and summer 20-year forecast that incorporates organic growth and growth associated with drivers like electrification (e.g., heating load and electric vehicles).

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.

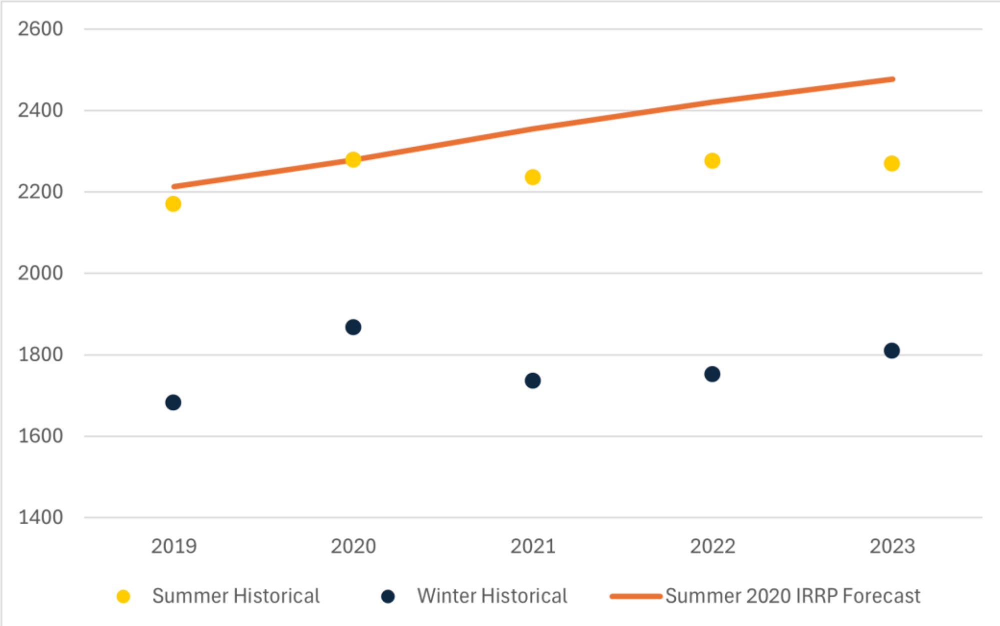
The regional planning process also considered non-coincident peaks which refers to each station's individual peak, regardless of whether these peaks occur at different times. Non-coincident peaks are used to understand the potential needs of the stations.

5.1 Historical Demand

Peak electricity demand within GTA North has historically occurred in the summer season. Figure 2, below, shows both the winter and summer coincident gross normal weather-corrected (adjusted to reflect normal weather conditions) historical demand for the GTA North region. Weather-corrected historical demands have been shown to remove the effect of weather on annual changes in demand, as they are more appropriate for evaluating growth trends. For context, Figure 2 also includes the summer peak demand forecast for the same years from the 2020 IRRP.

The gross weather-corrected demand for the GTA North region has averaged 2,245 MW in the summer and 1769 MW in the winter over the last five years preceding the IRRP start date (2019-2023).

Figure 2| Summer and Winter Historical Weather-Corrected Coincident Peak

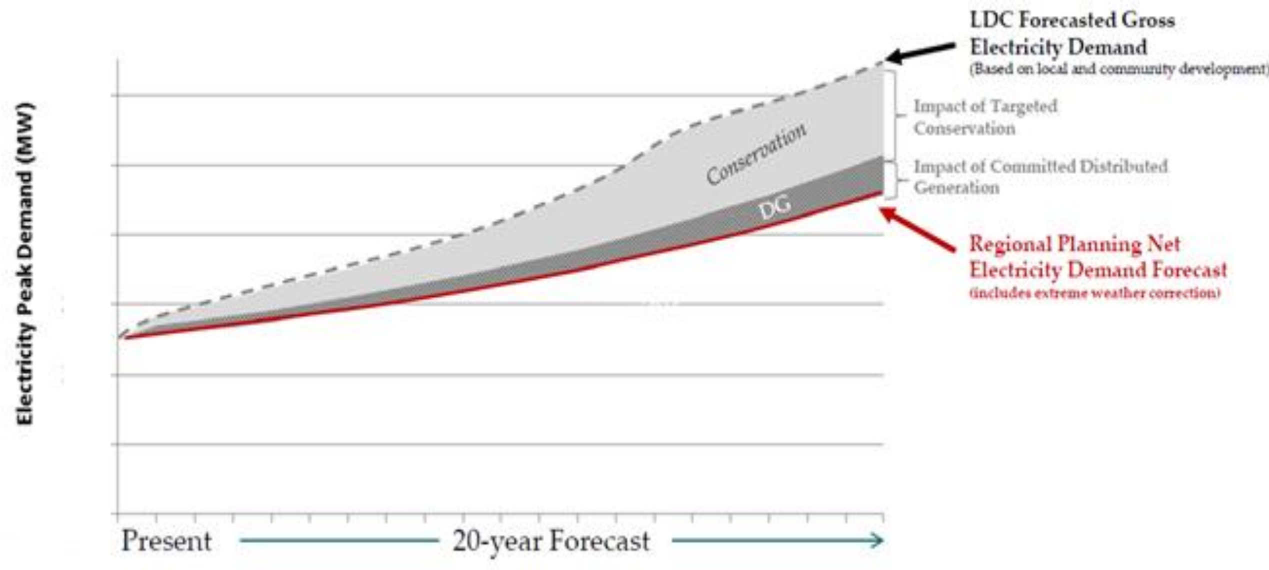


5.2 Demand Forecast Methodology

The methodology used to develop a 20-year IRRP peak demand forecast is illustrated in Figure 3. A gross demand forecast, which assumes the weather conditions of a normal year based on historical weather conditions (referred to as "normal weather"), was developed by the LDCs. This forecast was then adjusted to reflect the expected impact of extreme weather conditions to produce a reference forecast for planning assessments. Extreme weather conditions, as defined by the IESO, assume the worst observed weather over the previous 30 years. The forecast was then modified to reflect the expected peak demand impacts of provincial demand side management programs and DG contracted through previous provincial programs, such as renewable Feed-In Tariff (FIT) and microFIT standard offer programs. This net demand forecast was used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. The load forecast methodology is also informed by the Load Forecast Guideline for regional planning, which was formalized by the OEB's Regional Planning Process Advisory Group.

Figure 3| Illustrative Development of Demand Forecast



5.3 Gross LDC Forecast

LDCs are responsible for preparing the gross demand forecast as they have the most direct understanding of future local demand growth and drivers, informed by involvement with their customers, connection applicants, municipalities and the communities which they serve. Gross demand forecasts were prepared by the participating LDCs at the station level, or at the station bus level for multi-bus stations. The gross demand forecast generally accounts for increases in demand from new or intensified development, plus known 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). More details are provided in Appendix B.

The LDCs' forecasts considered the appropriate municipal plans for their service territories. The LDCs were 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 DG or new demand side management activities (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, expected 1 in 2 years), and provided station level loading at the time of the regional peak.

The IESO typically carries out demand forecasting at the provincial level, which is more applicable for bulk system analysis than regional. More details on the LDC load forecast assumptions can be found in Appendix B.

5.4 Contribution of Electricity demand Side Management

Electricity demand side management (eDSM, formerly Conservation and Demand Management or CDM) is a non-emitting and cost-effective resource that helps meet Ontario's electricity needs by reducing electricity consumption and peak demand and has become an integral component of provincial and regional planning. Electricity savings from demand side management is achieved through a mix of efficiency codes and standards, as well as eDSM program-related activities. These approaches complement each other to maximize 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 (e.g., residential, commercial and industrial consumers).

The estimated demand reduction from program-related activities was based on the IESO's 2024 Annual Planning Outlook eDSM savings forecast informed by the then current 2021-2024 Conservation and Demand Management (CDM) Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs assumed to be consistent with 2021-2024 framework savings levels. Through the 2021-2024 CDM Framework the IESO centrally delivered programs under the Save on Energy brand s to serve business and residential customers, as well as Indigenous communities. Following finalization of the IRRP's demand forecast, the Ontario government provided the IESO with the directive for the 2025-2036 Electricity Demand Side Management Framework, which expands the scale and scope of the Save on Energy programs, including launch of the Home Renovations Saving 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 reduce the magnitude of identified needs.

Figure 4 and Figure 5 show the estimated total yearly reduction to the demand forecast due to demand side management (from codes, standards, and eDSM programs). Additional details are provided in Appendix B.

Figure 4| Summer Peak Demand Reduction Due to Demand Side Management

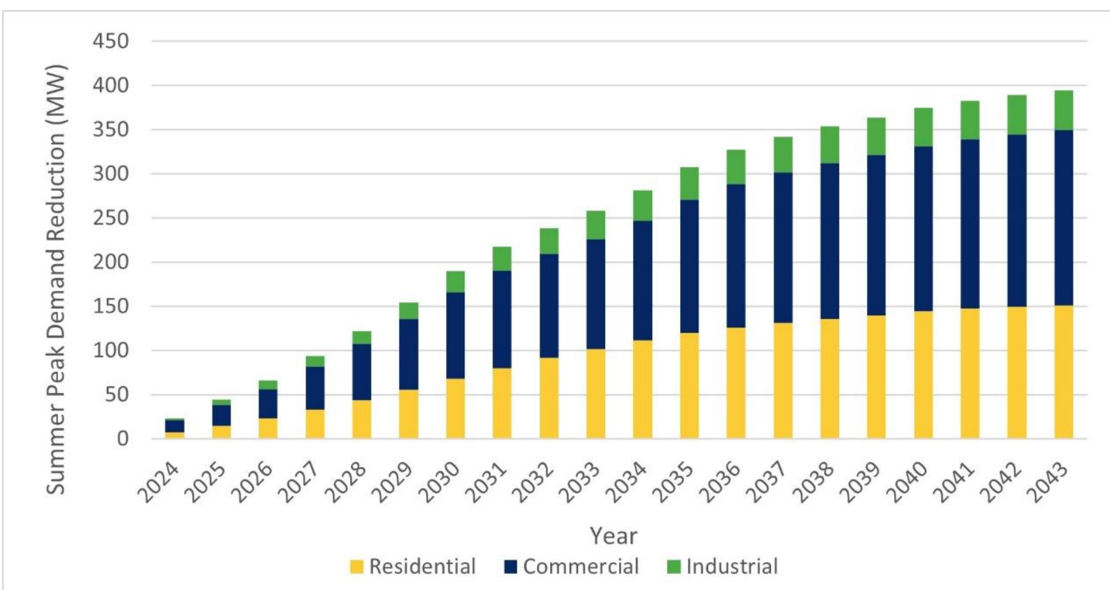
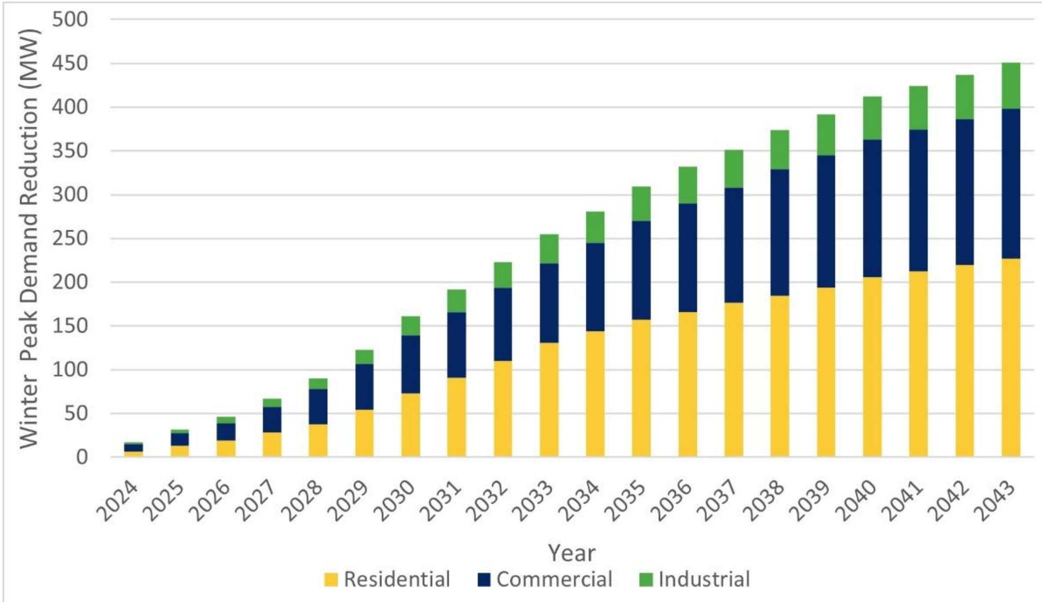


Figure 5| Winter Peak Demand Reduction Due to Demand Side Management

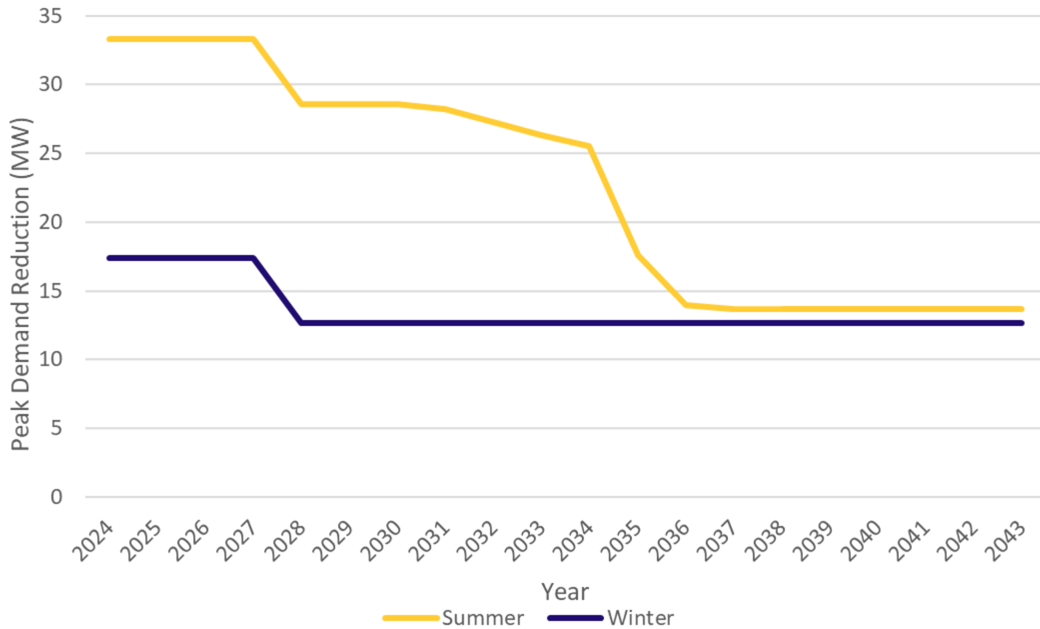


5.5 Contribution of Distributed Energy Resources to the Forecast

In addition to demand side management programs (which can include behind the meter DG), DG is forecasted to offset peak-demand requirements. The introduction of Ontario's FIT and microFIT Programs 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 Appendix B. The total contracted installed DG capacity in the GTA North Region is composed of a mix of renewable and non-renewable sources.

Figure 6 shows the estimated impact of DG on the GTA North Region demand forecast. The forecasted impact declines as existing FIT and microFIT contracted facilities reach the end of their contract terms throughout the late 2020s and into the mid-2030s.

Figure 6| Peak Demand Reduction Due to Distributed Energy Resources



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 driven by more than one station.

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

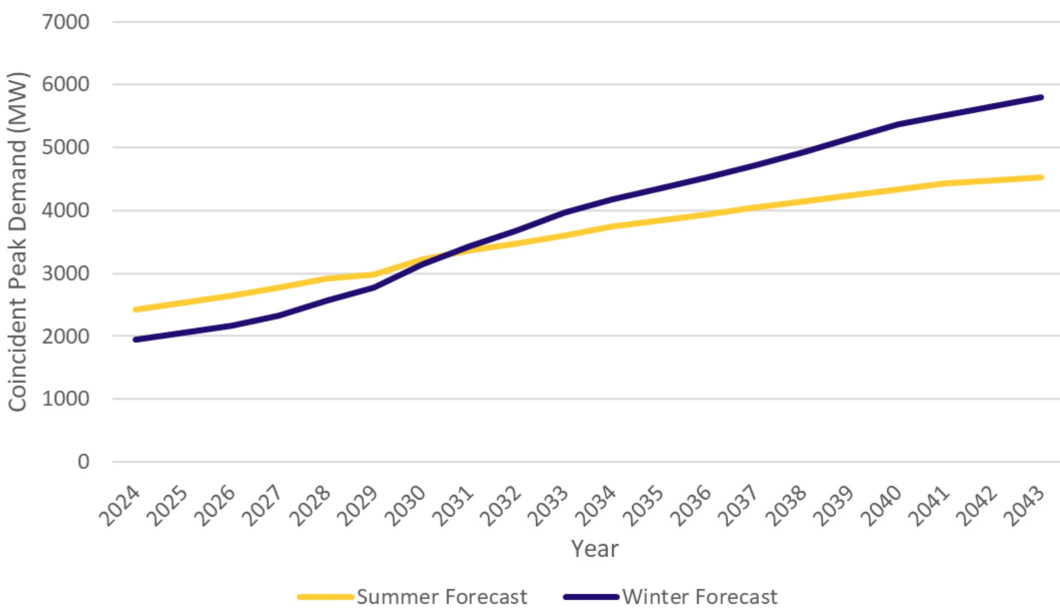
The first step is to adjust the coincident gross normal weather forecast for extreme weather conditions. The weather correction methodology is described in Appendix B. This results in a coincident gross forecast which assumes extreme weather. Two separate weather scenarios were prepared; one for extreme summer conditions, and one for extreme winter conditions.

Historically, York Region has experienced its highest loading conditions during summer months, driven by air conditioning loads. This is consistent with overall provincial peak conditions, which often occur on the same day and on similar, late afternoon hours as York Region. However, the expected adoption of electrified heating, namely heat-pumps, is forecast to significantly increase winter demand over the coming decades. While there is uncertainty around the rate of uptake, technology types, and operational decisions, a winter demand forecast was also developed to study the impact of higher winter peak growth rates. Both summer and winter peak forecasts were considered in this IRRP.

The last step is to adjust the resulting coincident gross extreme weather forecast for the impact of DG and demand side management. This is done by subtracting the forecasted DG and electricity demand side management (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 needs. Separate impacts were calculated based on typical summer and winter contributions of the load modifying resources during the peak hours, based on technology type.

The coincident net extreme weather forecasts ("planning" forecasts) for GTA North Region are shown in Figure 7.

Figure 7| GTA North 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 the potential for 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.

Additional details on how load profiles were created can be found in Appendix C. 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 through an Annual Working Group Meeting and as part of implementation of the plan.

5.8 Uncertainty in the Demand Forecast

The forecast for GTA North considers various growth drivers that each have an associated degree of uncertainty. The uncertainty in the regional planning process is managed through a flexible and adaptive approach that emphasizes monitoring, scenario analysis, and preserving future options. Development is only triggered when specific conditions are met within the designated development window, ensuring that investments are made based on clear and timely signals.

Based on the current forecast, the possibility of significantly higher winter growth rates may drive winter conditions to become more "limiting", or determine station capacity need dates, within the 2030s. This is in spite of winter ratings for transmission lines and stations being higher in winter than in the summer.

However, these winter forecasts also carry higher uncertainty due to factors like technology adoption and operational decisions, making them less reliable for immediate investment planning. Unlike summer peaks, which are largely informed by existing customer behaviour and technologies (notably widely used air conditioning), winter peaks assume continuous shifting of behaviour through adoption of electric heating and phase-out of existing gas heating. The adoption of electric heating is currently mainly driven through various level of government policies, economic incentives, and customer preferences. Due to the challenges with assuming how policy and technology will evolve over 20 years, the longer-term winter forecasts (2031-2043), have a greater level of uncertainty associated with them. They are considered in this IRRP for determining measures to preserve future options, but emphasis was placed on summer needs when determining timing of the required reinforcements.

Summer peak demand was used as a more certain foundation for guiding investment decisions, while actual winter demand trends will continue to be closely monitored to inform future adjustments. This strategy lays the groundwork for the plan to evolve cycle-to-cycle as clearer patterns emerge.

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 established power system reliability standards and criteria (IESO ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council (NPCC) Directory #1 standards), the Technical Working Group identified electricity needs in the near-term, medium-, and long-term timeframes. Near-term needs are expected to emerge within 5 years, and/or where immediate action is required. Medium- and Long-term needs are expected to emerge more than 5 years out, and immediate actions are not generally required, unless to preserve future options.

These needs are categorized according to the following:

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 periods of 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, e.g., 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 load meeting capability (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-001-4, and NPCC Directory #1. LMC studies are conducted using industry standard power system simulations.

Asset Replacement Needs are identified by the transmitter, informed by asset condition assessments, based on a range of considerations such as equipment deterioration due to age, weathering, heat stress 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. Asset replacement needs identified in the near-term timeframe would typically reflect condition-based information, while replacement needs identified in the longer term are often based on the equipment's expected service life. As such, any recommendations for medium- or long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

Load Security and Load 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 for Ontario are described in Section 7 of the ORTAC.

Technical study results for the GTA North IRRP can be found in Appendix E. The needs identified are discussed in the following sections and are shown in the proceeding sections.

6.2 Near-Term Needs (2026-2030)

6.2.1 Station Capacity Needs

Step-down station capacity needs are determined by comparing the station peak demand forecast to the facility's LTR. In many cases, need dates can be deferred by transferring load at a station expected to reach or exceed its LTR to another nearby station that has available capacity. Feasible load transfers are already assumed in the station-level demand forecast based on input from LDC members of the Technical Working Group about the transfer capabilities and typical loading practices.

Stations will typically have a lower LTR for summer months than for winter months, as colder ambient temperatures allow more power to flow through equipment without overheating transformers and other station equipment. When a station reaches its annual peak during summer months, this becomes the only forecast scenario which requires study, as it is the most limiting condition. When stations reach their peak during winter months, however, both summer and winter forecasts should be considered as the higher winter loading may be offset with higher ratings, and either season could ultimately be the more "limiting" scenario.

When a step-down station's capacity is reached (summer or winter), and after feasible load transfers are accounted for, options for addressing the need include reducing peak demand in the supply area (i.e.., through EE or DERs) or building new step-down transformer capacity to serve incremental growth.

Typically, where there is sustained new urban growth and development in an area, measures to reduce the peak demand cannot defer or avoid the need for new station capacity indefinitely. Planning recommendations are informed by comparing the cost of these measures to the value of deferring construction of a new or expanded station.

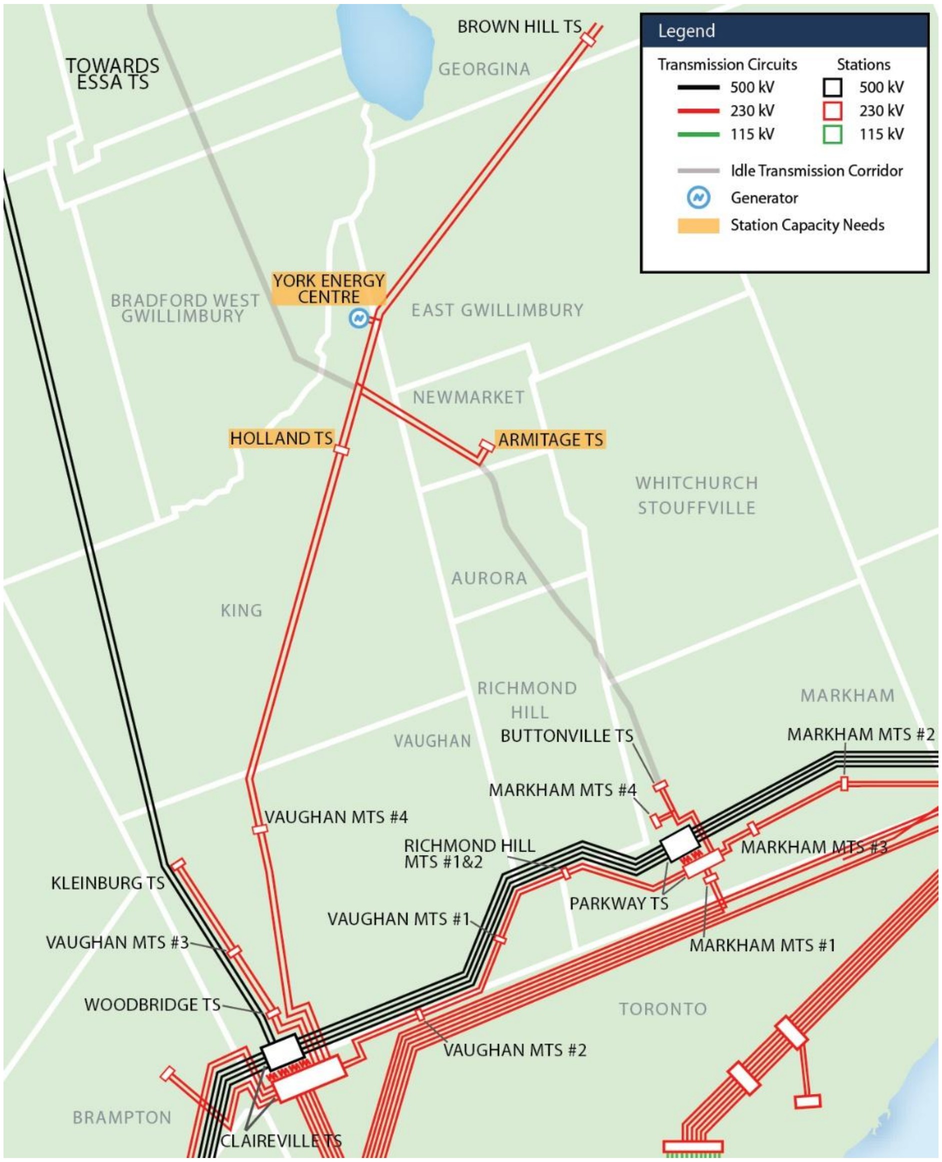
Before a new step-down station can be built, a suitable location must be identified. Stations must be connected to a part of the broader transmission system with enough incremental capacity available to reliably supply the station load. The station must also be located close enough to the anticipated customer demand to ensure that the distribution network is capable of supplying customers reliably.

Additional information on specific station capacity needs anticipated in GTA North in the near term are provided in the sections that follow.

6.2.1.1 Northern York

Northern York Region[2] electrical service territory is currently supplied by four step-down stations. Armitage TS and Holland TS are located in proximity to Newmarket and Holland Marsh, respectively, while Brown Hill TS is located further north, near Georgina, and Kleinburg TS further south, at the border between Caledon and Vaughan. Recent load growth within northern York has been served through Armitage TS and Holland TS, and forecast growth continues to be concentrated in the areas supplied by these two stations.

Figure 8| Northern York Station Needs



Although electrical service territories do not correspond directly to municipal boundaries, Armitage TS and Holland TS generally supply Newmarket, Aurora, East Gwillimbury, and parts of Bradford-West Gwillimbury, King Township, and Whitchurch-Stouffville.

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[2] Term is used to refer to areas served by electrical infrastructure in the northern half of the North GTA planning area. While this roughly aligns with northern York Region, it is also inclusive of parts of neighbouring municipalities such as Bradford West Gwillimbury (county of Simcoe)

Brown Hill TS, being further north and east, supplies mainly rural areas with lower anticipated growth rates, though there is potential for longer term growth within its service territory, primarily Georgina and East Gwillimbury.

Kleinburg TS primarily serves loads in and around Bolton, as well as some rural loads throughout King township and Caledon. Supply options to meet growth in the Kleinburg TS service area, primarily concentrated in Bolton and Caledon, are currently being studied in the GTA West IRRP, though outcomes have been factored into system models used in this study.

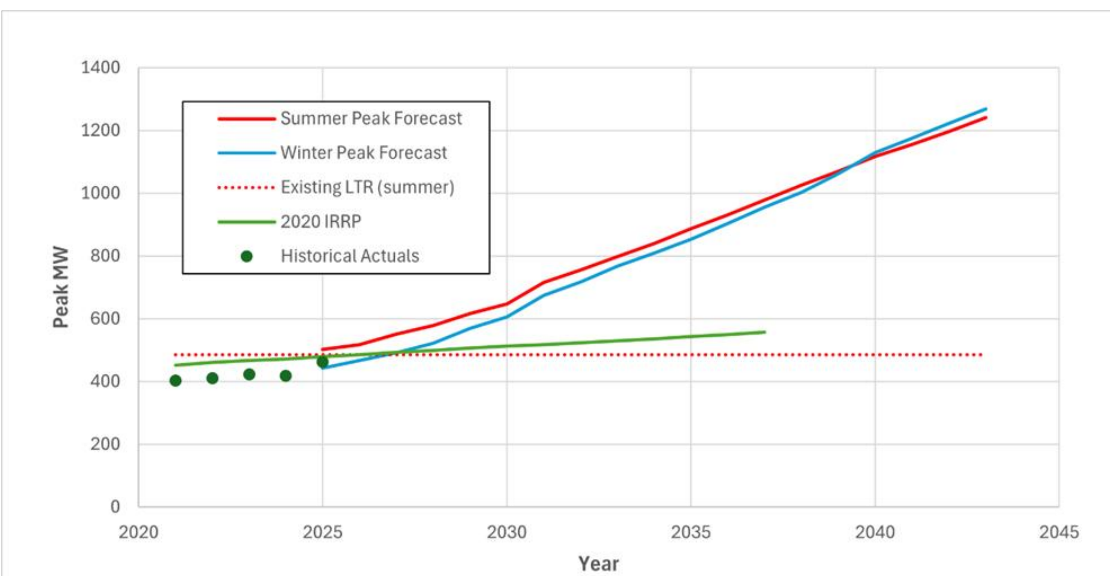
Of the four existing step-down stations, all but Brown Hill TS are currently loaded close to the maximum capability. Due to the distance between Brown Hill TS and the Armitage TS and Holland TS service territory, Brown Hill TS is not a suitable facility for transferring excess load without incurring significant distribution costs. The combined station capacity need in Northern York is summarized in Table 4. There is an immediate need to supply an additional 16 MW of demand and thus need increases to 750 MW by the end of the study forecast period.

Table 4 | Northern York Station Capacity Needs

Stations	Timing	2025	2035	2043
Holland TS Armitage TS	Immediate	16 MW	400 MW	755 MW

The combined summer peak demand forecast of the approximate Armitage TS and Holland TS service territory is shown in Figure 9 along with their combined maximum rated station capacity. Also shown for comparison is the demand forecast from the 2020 York IRRP.

Figure 9 | Northern York Demand Forecast

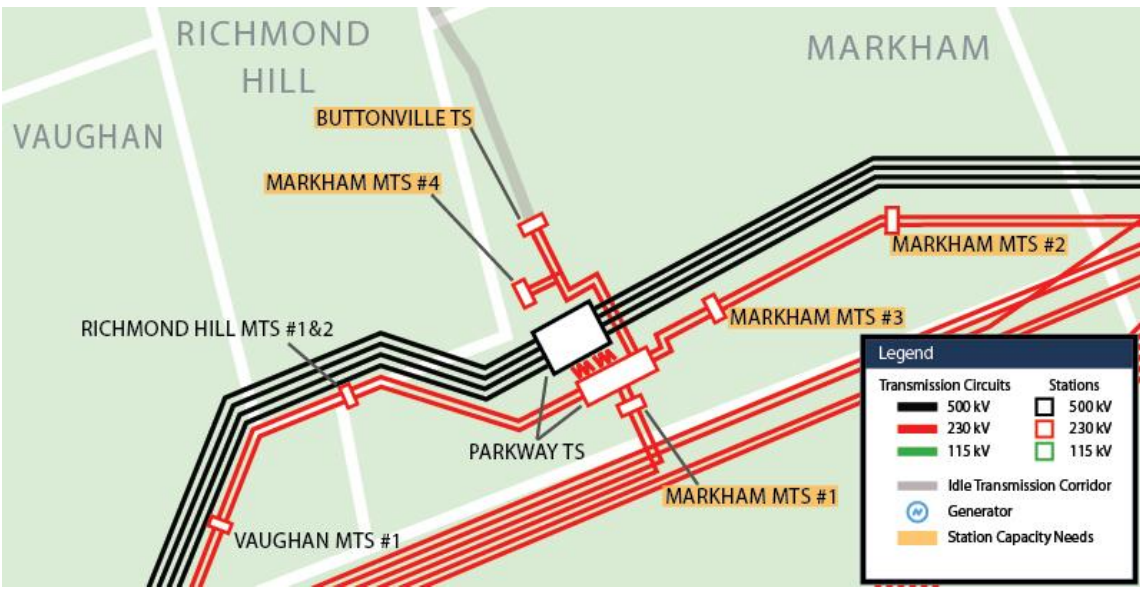


The previous IRRP had identified Northern York as having station capacity needs emerging in 2027. The development of Northern York TS #1 was recommended to address this need with a targeted in-service date of 2027, and a connection point in the vicinity of the existing Holland TS. However, based on revised demand forecasts, the need has been advanced and is now considered immediate.

6.2.1.2 Markham

Due to the ability to transfer loads between their southern stations, Alectra has typically alternated construction and loading of new stations between Markham and Vaughan to serve loads within their southern York service territory (roughly aligned with Vaughan, Richmond Hill, and Markham).

Figure 10| Markham and Area Station Needs



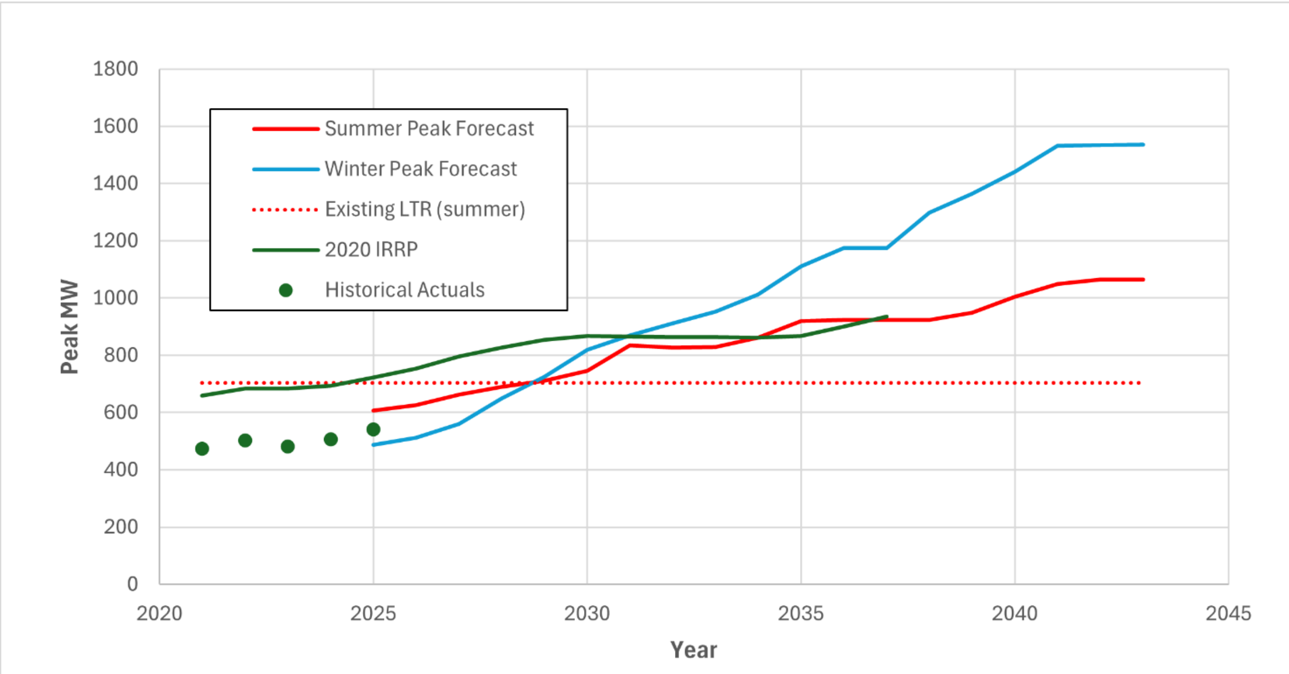
The last stations placed in service for southern York Alectra customers was Vaughan MTS #4 in 2018, preceded by Markham MTS #4 in 2011. Both of these stations had been located along the two possible transmission sections which span north from the main transmission supply path along the southern border of York region (adjacent to Highway 407). This had been done to meet the challenge of connecting increasingly northern development despite a transmission system that remains concentrated to the south.

Table 5| Markham and Area Station Capacity Needs

Stations	Timing	2025	2035	2043
Markham MTSs	Near-term	0 MW	241 MW	426 MW

The combined summer peak demand forecasts of Markham area stations (including Markham MTS #1, #2, #3, #4, and Buttonville TS) are shown in Figure 11, below, along with their combined maximum rated station capacity. Also shown for comparison is the equivalent demand forecast from the 2020 York IRRP.

Figure 11 | Markham and Area Demand Forecast



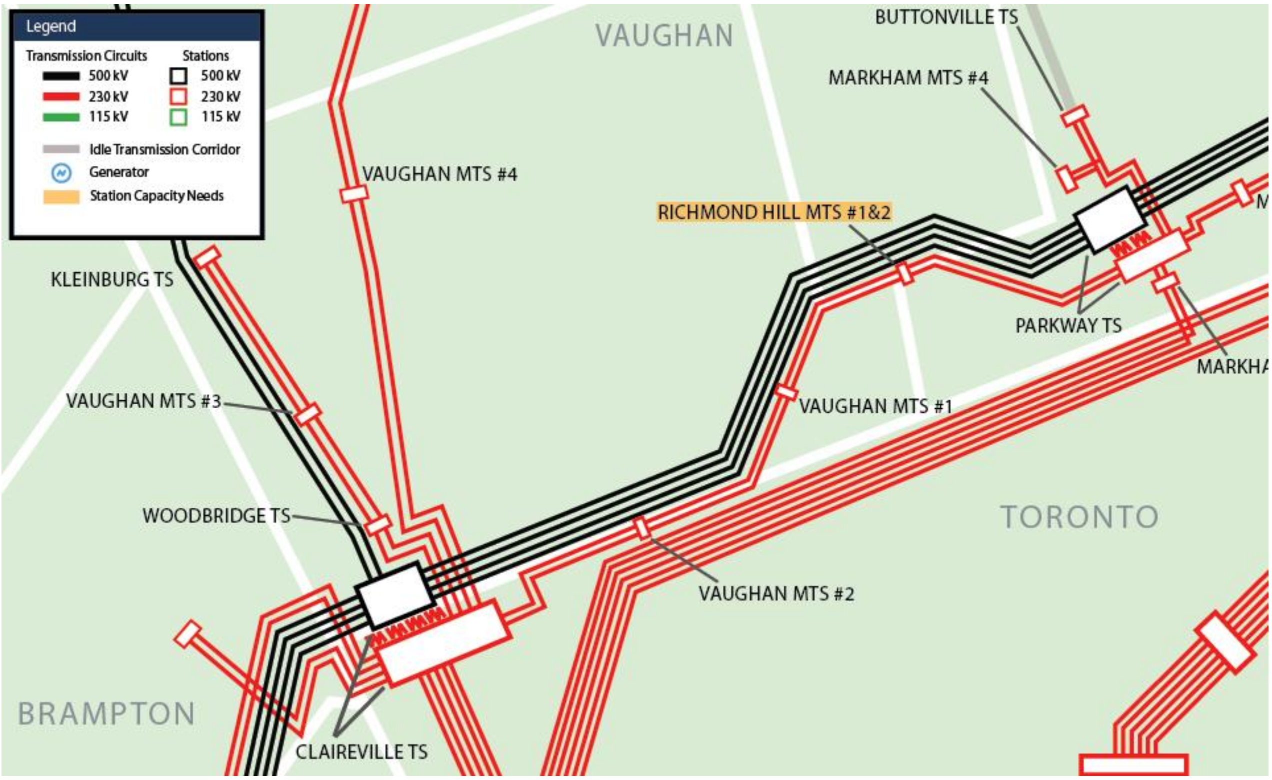
Periods of the forecast which show a relatively flat profile indicate the years in which incremental growth is expected to be met through allocation to a future Vaughan area station, resulting in no incremental growth being applied to Markham area stations. The next Vaughan area station is not expected to be required until the early 2030s (See section 7.4.1.1).

In addition to meeting total supply capacity needs of customers, addressing stations needs will also require consideration of the suitable location to site future stations, to ensure proximity to end use customers. Locating step down stations too far from customers can result in lower customer reliability and power quality, and additional distribution costs to run feeders to connect customers. Finding suitable locations to site stations to serve southern York customer loads has been increasingly challenging in recent years, as limited transmission paths exist north of the southern border.

6.2.1.3 Richmond Hill

Richmond Hill is currently the site of two step-down stations, Richmond Hill MTS #1, and Richmond Hill MTS #2. Both stations have been loaded to capacity for most of the past few summers, with new load growth in Richmond Hill supplied via load transfers to stations in Vaughan or Markham.

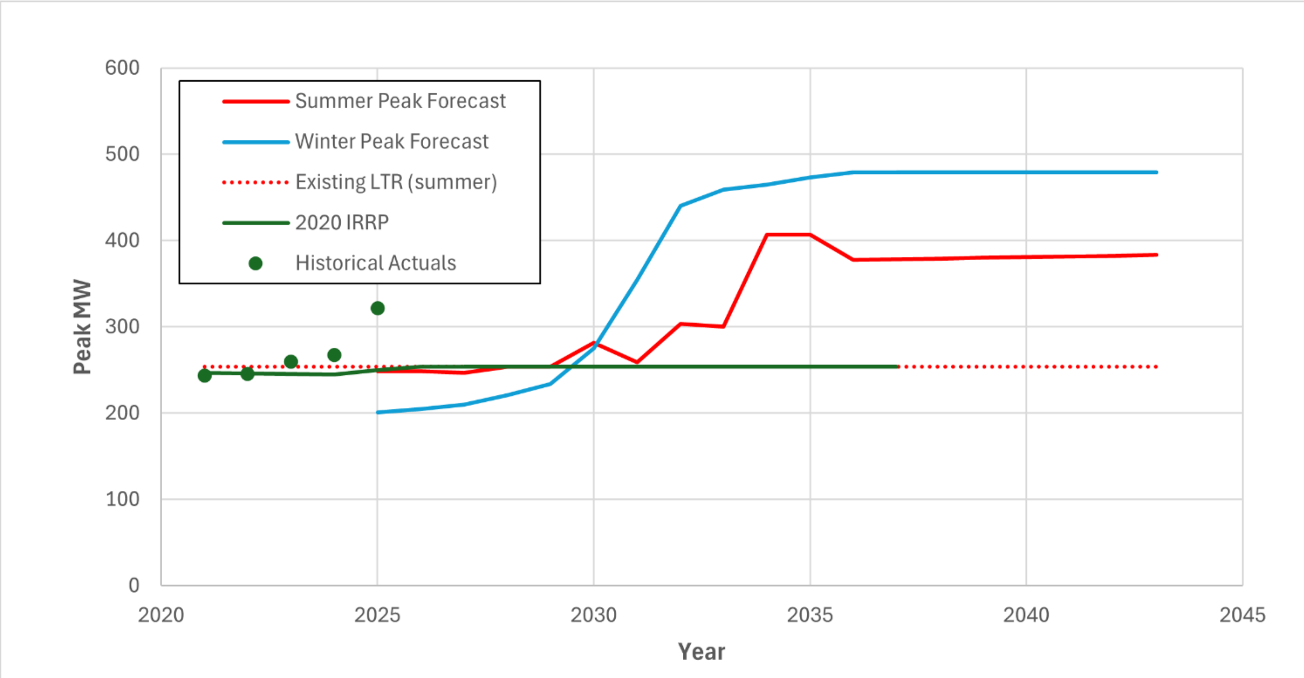
Figure 12| Richmond Hill Station Capacity Needs



Although Richmond Hill has been managing similar complexities of providing supply to increasingly northern development, a new area of intensification is emerging in the southern part of this municipality. The area, roughly corresponding to the Richmond Hill Centre (RHC) Urban Growth Centre, is the result of the planned extension of the Yonge subway into Richmond Hill and Markham. Significant, intensified development, with associated electrical demand, is anticipated in the vicinity of these new development zones.

Figure 13 shows the relatively steady loading at the existing Richmond Hill stations in recent years, and the expected impact of new growth over the coming years in the surrounding area. Growth anticipated around the new subway extension has been included in this grouped area, while growth further north (better served through northern stations in Markham and Vaughan) has not been included. Note a large jump in actual peak demand for the summer of 2025 is the result of load transfers supplied by Richmond Hill TSs during emergency conditions. The irregular loading of the summer forecast is the result of anticipated load shifting as new stations come online.

Figure 13| Richmond Hill Demand Forecast



The need for a new step-down station in Richmond Hill was not identified in the previous IRRP published in 2020. Instead, this new need is in direct response to new, intensified development in proximity to the planned Yonge subway extension. The anticipated need date for additional station capacity is 2030.

6.2.2 Supply Capacity Needs

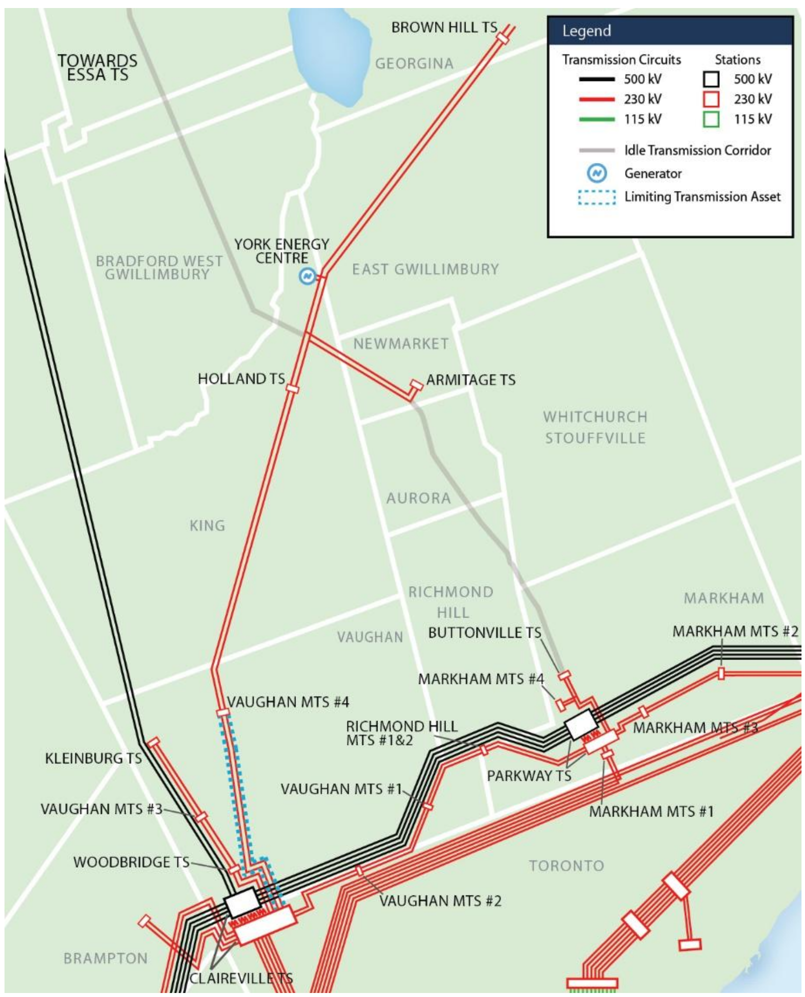
Supply capacity needs are often described in terms of a system's Load Meeting Capability (LMC), which is the maximum amount of demand that can be supplied by a transmission circuit or group of circuits, before specific system criteria are violated. Where the demand forecast is expected to exceed the LMC, mitigation measures will be required. These can vary from lowering load to at or below the system LMC (through NWA or similar measures), upgrading the system to a higher LMC, or, depending on the type of criteria, arming load rejection (to automatically disconnect loads during a contingency to keep total demand below the LMC).

Supply capacity needs are determined based on the system performance following the simulation of standard criteria or "contingency events" during peak demand conditions. The loss of a single transmission element is referred to as an N-1 event, while simultaneous loss of 2 elements is N-2. Following N-2 events, the criteria allow for customer load loss up to a certain amount in order to keep loading on the remaining transmission facilities within acceptable limits. These "load rejection", or LR events, represent lower reliability for customers, but only in the event of a major transmission outage occurring during peak loading conditions. Although a certain amount of LR is permitted in these cases, it is not a preferred outcome, particularly when designing solutions to fully address system needs. As a result, this study distinguishes between needs and solutions required to meet N-2 conditions both with and without LR. No load loss is permitted following N-1 contingencies.

6.2.2.1 Northern York

The Northern York electrical region is primarily supplied by one double-circuit 230 kV transmission line, which transfers power stepped down from the bulk 500 kV network at Claireville TS, and transports it northward to supply the step-down stations of Northern York. The line also directly supplies large customer connections and will supply a planned Go Transit power traction station. A second supply source connected to these 230 kV circuits is the York Energy Centre (YEC) peaker plant. This 400 MW gas-powered facility generates power when local demand exceeds the ability of the existing transmission line to reliably supply local needs and can also be dispatched to ensure provincial resource adequacy in high-demand periods. Due to its ability to rapidly respond to sudden changes in demand, YEC is useful for balancing output from intermittent energy sources, or to respond quickly following system contingencies and outages.

Figure 14| Northern York Supply Capacity Needs



There are two main double-element contingencies that result in the thermal overload on H82/83V based on the current demand forecast.

- The loss of T1B breaker at Holland TS causes the simultaneous loss of H83V and the York Energy Centre from service as YEC's stations service is supplied from Holland TS. Due to the loss of YEC's station service, approximately 400 MW of capacity is also lost. Due to these conditions, the companion circuit, H82V becomes overloaded in 2025.[3] Note that the recently commissioned Battery Energy Storage System (BESS) at YEC remains in service during this outage and improves the LMC of the system by approximately 50 MW.
- A breaker failure at L82L88 at Holland TS simultaneously removes circuits H82V and B88H from service. While this does not remove YEC from service, under normal operating conditions it will remove the G1 unit, and up to ~200 MW of generation. The BESS unit, which is connected through the G1 yard, would also be removed from service during this contingency. At peak demand, due to these conditions, the companion circuit, H82V would become overloaded in 2027.[4]

Additional Needs in Northern York – Under and Over Voltage

Undervoltage

In the event of the simultaneous loss of H82V + H83V, this sub-system becomes radially supplied from the north, via Minden TS through B88/89H. Due to the length of B88/89H, especially in high load conditions, the subsystem's voltage drops to unacceptable levels. With the loss of H82/83V, York Energy Centre is unable to provide voltage support due the station supply coming from Holland TS (which is lost by configuration following this contingency).

In addition to unacceptably low voltage levels within York region, under high load conditions this contingency would cause overloads on sections of the M6E circuits running between Essa TS and Minden TS, as this becomes one of the few remaining routes for power to flow into northern York.

The YEC BESS is not removed from service by this contingency, and while it does help provide support, it is not sufficient to address voltage needs in Northern York or overloads on M6E. Based on the current forecast, this need materializes in 2025.[5]

Overvoltage

The simultaneous loss of B88H and B89H removes Armitage TS, Brown Hill TS, and YEC from service, and leaves a lightly loaded radial circuit from Minden TS supplying the relatively smaller load centres at Beaverton TS and Lindsay TS. Due to the length of the circuits from Minden TS towards Northern York, especially in lighter load conditions, the subsystem is like to experience an unacceptable increase in voltage. This is further exacerbated by the presence of the use of capacitor banks at Beaverton TS and Lindsay TS, which help support low voltage conditions when the full system is in service and voltages are at risk of running low. This need had been identified within the last IRRP. Although actions have not yet been taken to fully address it, unacceptably high voltages haves not been observed within the area

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[3] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

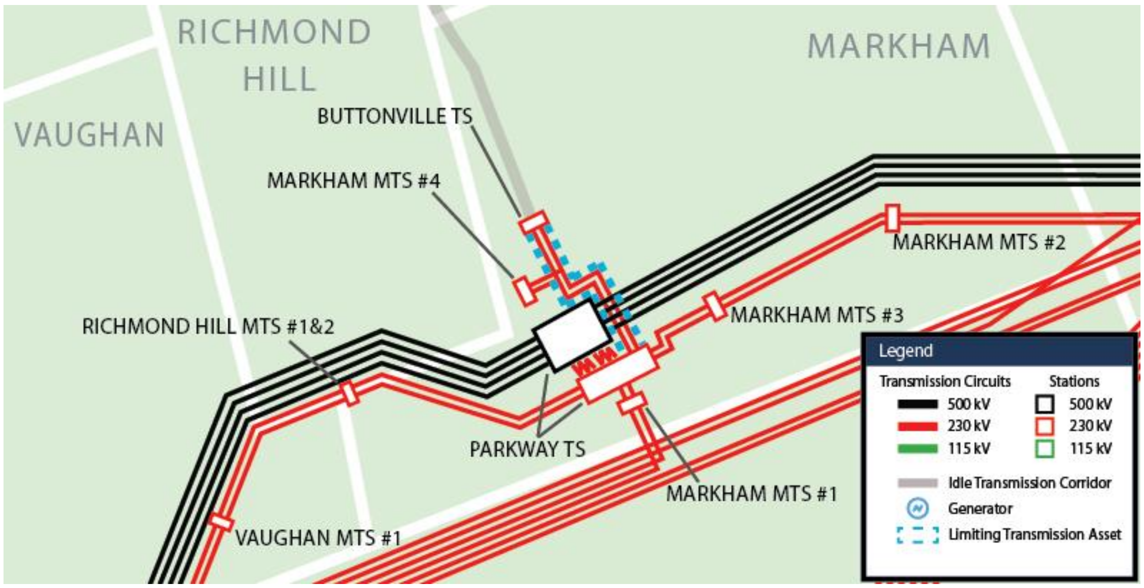
[4] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

[5] Including load rejection of 150MW. Note that the system is currently relying on arming Load Rejection (LR) during peak periods in order to manage the risks associated with the T1B breaker failure.

6.2.2.2 Markham and Area (Parkway-Buttonville)

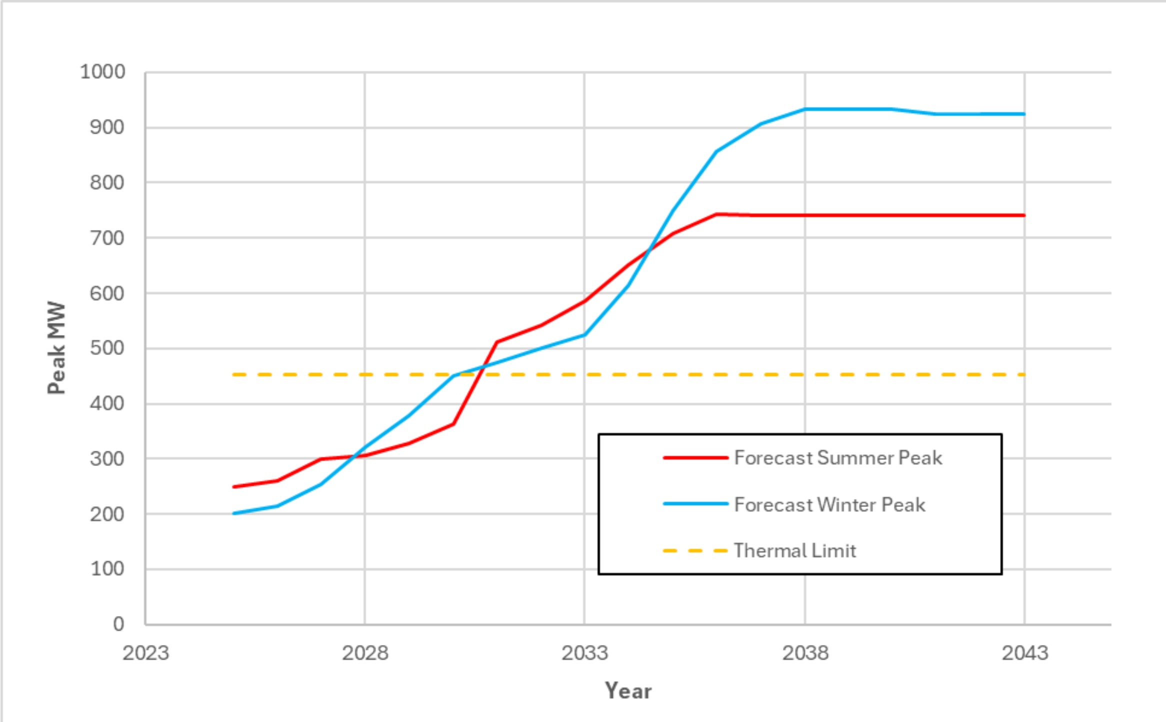
The Parkway – Buttonville radial circuit is a two circuit (P45/46), 230 kV transmission tap which currently stretches approximately 6 km north of Parkway TS into Markham region. Power stepped down from the bulk 500 kV system at Parkway TS and flows north to supply two step-down stations, Markham MTS #4 and Buttonville TS.

Figure 15| Parkway-Buttonville Supply Capacity Needs



As the only existing northern link into Markham region, this circuit is expected to be loaded with a new step-down station, Markham MTS #5, recommended in the previous IRRP. The maximum loading on this circuit is approximately 450 MW and is based on the thermal limit of the companion circuit when one of either P45 or P46 is out of service. The forecast load to be served by this circuit is shown in the graph below, along with the existing transmission thermal limit:

Figure 16| P45/46 loading forecast for southern section, and Thermal Limit



The existing transmission circuits are roughly sufficient for serving both existing stations to their summer LTR, plus an additional 133 MW from a new step-down station. Based on the planned in-service date of Markham MTS #5, and loading rate, this need is expected to be reached in 2031.

6.2.3 Load Security and Load Restoration Needs

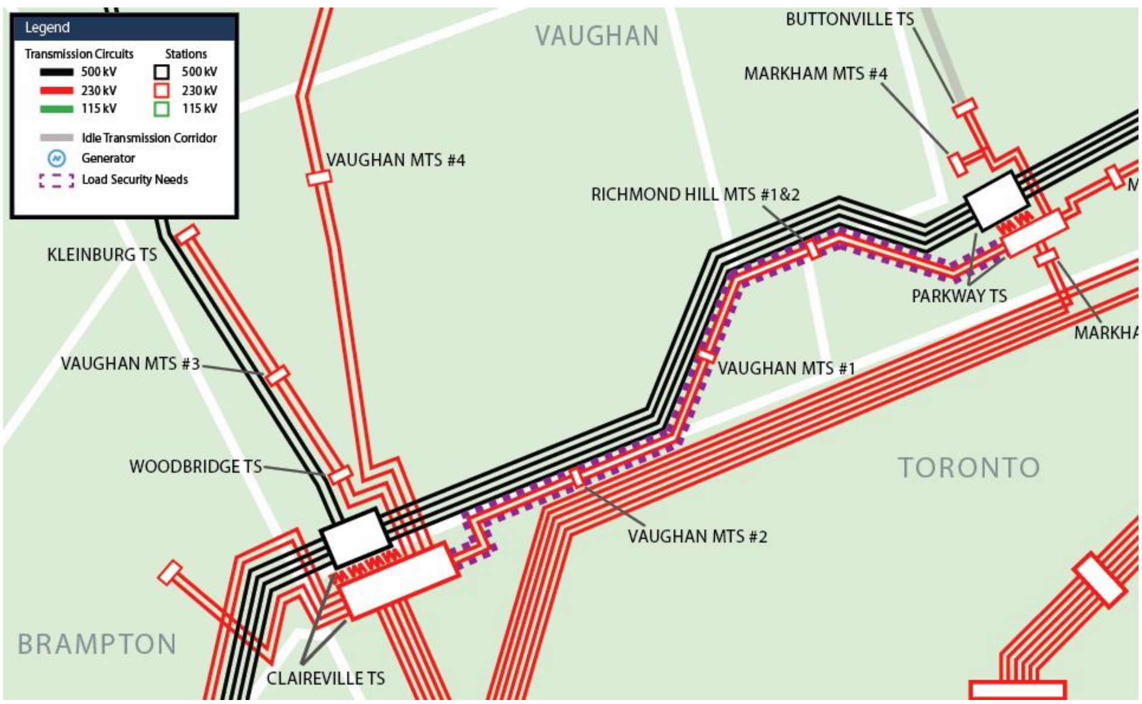
Load Security and Load Restoration needs refer to the level of reliability customers can expect when major contingencies occur. Security refers to the maximum amount of load which can be simultaneously lost following any of the defined planning contingency types as specified in ORTAC. In general, no more than 600 MW is permitted to be lost after an N-2 contingency through a combination of loss by configuration (from loss of supply to a station), or Load Rejection (automatically tripped load to keep remaining facilities within their applicable loading limits). Load Restoration refers to how quickly load can be reconnected after a major transmission outage. It can be determined by factors such as the distribution network's ability to transfer loads to other nearby stations, remoteness, and the nature of the interruption/equipment affected (e.g., overhead versus underground facilities) York Region typically performs well for restoration, given Alectra's meshed distribution network, the proximity of Hydro One crews and equipment to the GTA, and the mainly overhead transmission system. Due to good historical performance, no restoration needs have been identified in this area which require actions to be taken at this time. Security needs are outlined below.

6.2.3.1 Southern Vaughan/Richmond Hill (Parkway-Claireville) Security Needs

The Parkway to Claireville circuits are a double 230 kV transmission line which spans between Claireville TS and Parkway TS, roughly adjacent to Highway 407, along the southern border of Vaughan, Richmond Hill, and western Markham. Supply is provided from the bulk network at both ends of this corridor, as Claireville TS and Parkway TS both have autotransformer connections to supply the 230 kV system from the 500 kV system.

Five municipal step-down stations are connected to the corridor today (Vaughan MTS #1, Vaughan MTS #1E, Vaughan MTS #2, Richmond Hill MTS #1, and Richmond Hill MTS #2). When all stations are fully loaded to their LTRs, up to 713 MW can be supplied at once, with the 600 MW security limit frequently being exceeded. These load levels were exceeded during the recent 2025 summer peak, when total loads reached 734 MW due to load transfers from neighbouring stations to address a separate distribution outage.

Figure 17| Parkway to Claireville circuits (V71/75P)



This corridor has previously been flagged as being at risk of violating security limits. In previous regional plans, it was recommended that remote operated switching facilities be installed along this corridor. These have since come into service and allow approximately half the load along this corridor to be restored in a short amount of time in the event of an N-2 contingency removing the entire corridor from service. Although this does not eliminate the risk of losing over 600 MW, it was determined that this solution would substantially address customer reliability needs, at a relatively low cost, while improving operational flexibility.

However, the present-day security need is expected to worsen when the planned Richmond Hill MTS #3 comes into service, tentatively scheduled for 2030. When all stations are fully loaded up to their LTRs, up to 866 MW could potentially be at risk of interruption in the event of a N-2 contingency occurring during summer peak.

Table 6 | Parkway to Claireville Load Security Needs

Infrastructure	Timing	2025	2035	2043
Parkway to Claireville 230 kV	Immediate	94 MW	293 MW	359 MW

This represents a significant increase in the potential violation of security criteria for the area. The application of security criteria has also recently been amended through a revision to ORTAC, placing greater urgency on the need to address outstanding security needs, and only consider exemptions (as had been in place) as a temporary measure. Both the increases in demand forecasts and changes to security criteria, now require this security need to be treated as urgent.

6.3 Medium- and Long-Term Needs (2031-2040)

This section outlines longer term needs (expected to arise in 5+ years timeline), where development actions are not yet required to be undertaken. However, actions may still be required to preserve options, for instance, in the identification and preservation of land to accommodate future facilities. This is particularly the case for needs anticipated within the 5 to 10 year timeframe (medium- term needs).

GTA North is expected to be a winter-peaking region by early 2030s. As discussed in Section 5.8, demand forecasts associated with winter peaks carry a level of uncertainty as they are associated with customer behaviours and the rate of adoption of electric heating. Understanding where future needs are expected to emerge will influence planning on the transmission system to ensure upgrades can be made in time to allow for reliable connection.

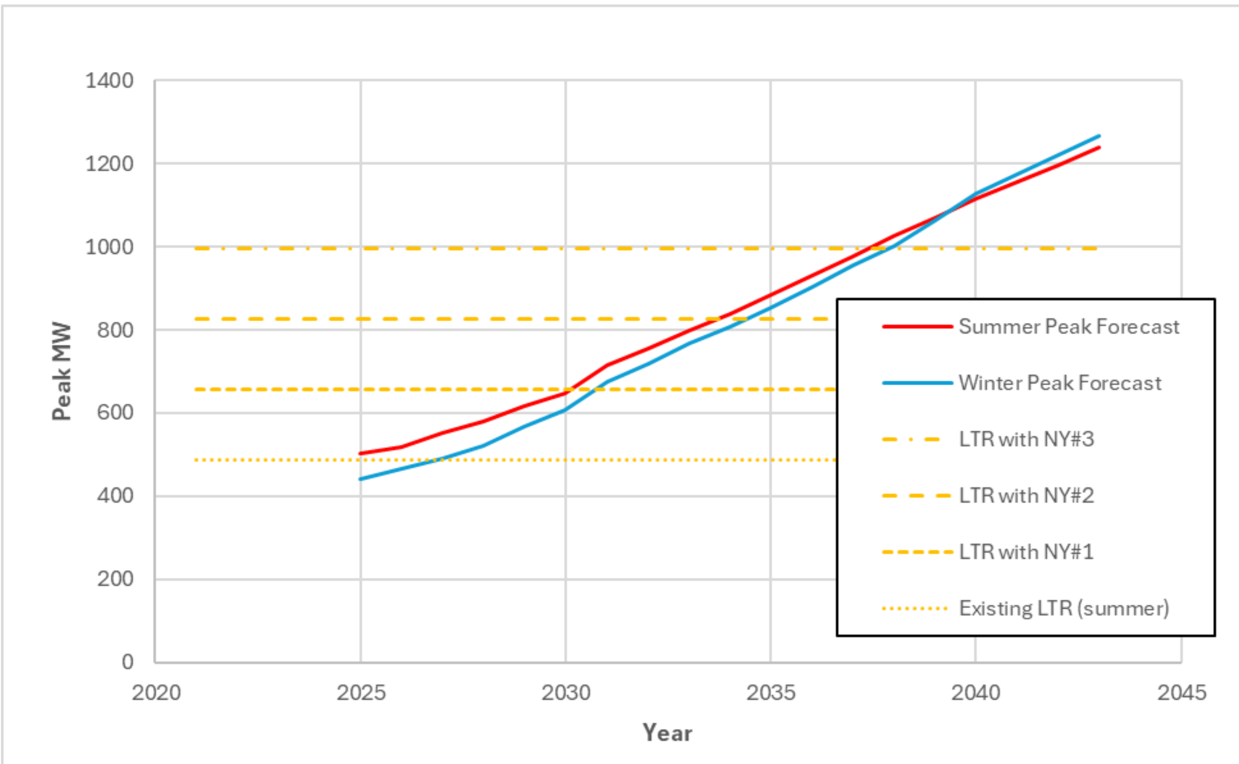
6.3.1 Station Capacity Needs

The need for step-down stations beyond the next five years is predominantly based on longer-term municipal growth forecasts and is subject to change as actual connection requests and development occurs. In particular, sudden large connection requests for major commercial customers (such as data centres) could significantly advance need dates. Longer-term step-down station needs may also need to account for winter loading conditions.

6.3.1.1 Northern York

Northern York Region is expected to continue to see significant increases in electrical demand over the next 5-15 years, driven by new development, large customer loads, and electrification of transportation and home heating. After the planned development of the future Northern York TS #1, whose need was described section 6.2.1.1, growth is expected to continue throughout the area. The graph below shows the incremental long-term challenges of meeting station capacity needs when both summer and winter needs are considered:

Figure 18| Northern York station capacity limits

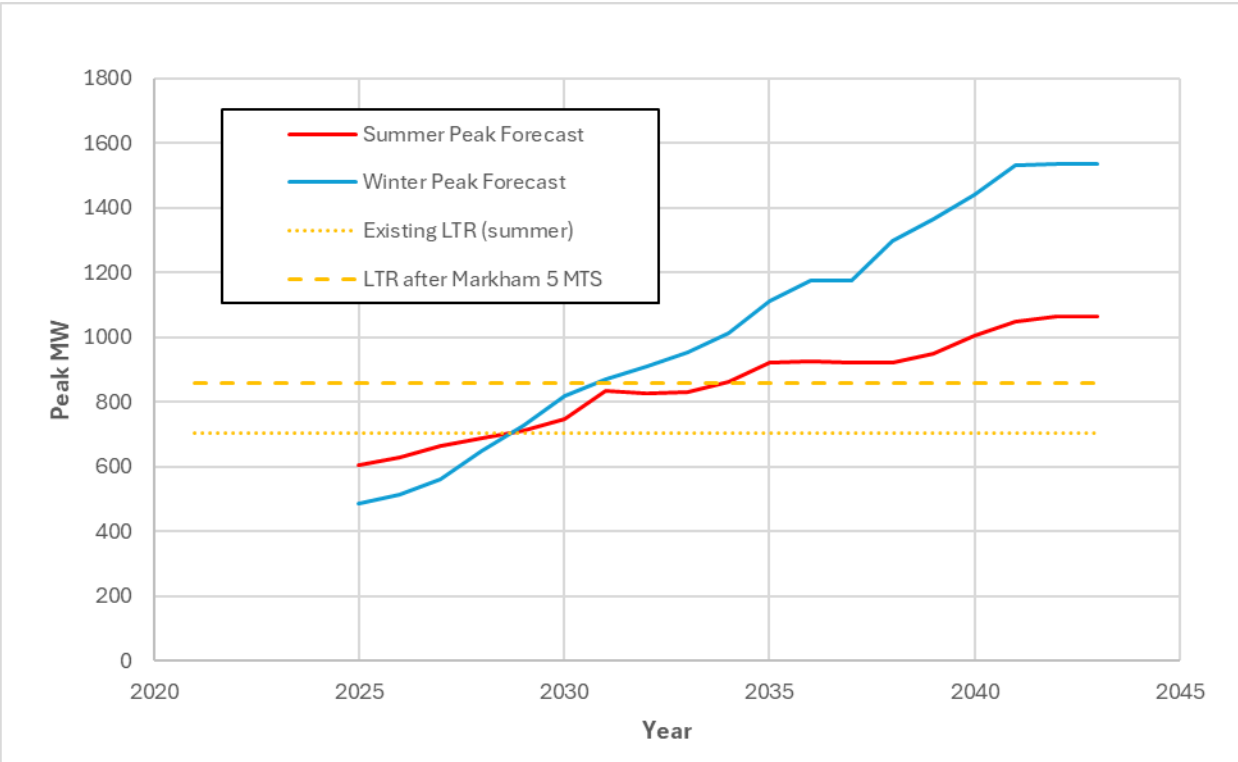


Need-dates for the second new station will depend on actual growth rates. Given the size of northern York regional, there may also be challenges associated with serving growth in the Whitchurch-Stouffville area from the future Northern York TS #1 (expected to be located over 20 km away, in King). As a result, a second new station to serve Northern York (notionally Northern York TS #2) is recommended to be located in closer proximity to eastern York load centres. In the longer term, current growth rates suggest new Northern York step-down stations may be triggered roughly every four or five years for summer-peaking conditions, or more frequently if winter-peak demand growth conditions emerge as per the forecast.

6.3.1.2 Markham

Long-term growth throughout the Alectra service territory of southern York is expected to continue at an aggressive pace in the longer term. Based on the existing summer peak forecast, and assuming the near-term need for capacity is met through Markham MTS #5, additional step-down capacity would be required in 2034.

Figure 19 | Markham supplying stations, and station capacity limits



Factors such as DER uptake, pace of electrification, and residential and commercial development rates can all affect the actual need date.

As described in section 6.2.1.2, finding locations suitable for new step-down stations to meet forecast load growth in Markham has been challenging in recent years, as the existing bulk transmission system runs roughly along Highway 407 in the area, with only a 3 km extension northward. Solutions to meet near term stations capacity needs generally only consider connections to the existing transmission system as new transmission cannot be developed in less than five years. However, for longer term station needs, consideration can be given to connection points along new transmission if no feasible connection points exist from either a capacity perspective or geographic proximity. Based on concerns expressed by LDCs with serving anticipated growth centres throughout northern Markham (and northern Richmond Hill) from the existing network, siting Markham MTS #6 cannot be accomplished without new transmission in order to site the step-down capacity closer to the anticipated growth.

6.3.1.3 Vaughan

Similar to the near-term needs identified in southern Richmond Hill (described in section 6.2.1.3), there is a longer term need to provide step-down station capacity in southern Vaughan. This is directly the result of new major commercial and residential development and intensification from the Vaughan Metropolitan Centre (VMC) Urban Growth Centre. As a result, the need is not linked to remaining capacity at other nearby stations, but to the intensified demand associated with growth in this pocket. The current anticipated need date is 2033, and while this is just outside the 5-year horizon defined as near term, work is ongoing by Alectra to find suitable land and begin development to meet the targeted in-service date. The notional Vaughan MTS #5 is likely to seek connection to the existing V71/75P circuits, as these transmission facilities are near the anticipated VMC growth area. This would exacerbate existing security needs along V71/75P corridor. This would exacerbate existing security needs along V71/75P corridor.

6.3.2 Supply Capacity Needs

Supply capacity needs emerging in the longer term are generally a result of either higher loading requirements due to new step-down stations or impacts on local supply capacity resulting from potential phase out of local generators as contracts expire. System conditions can also be impacted by planned changes to the bulk system, with implications for both system needs and available solutions.

6.3.2.1 Northern York

Capacity needs for supplying incremental load growth in the near term were described in section 6.2.2.16.2.1.1, and roughly correspond to the amount of supply required to enable the connection and full loading of one additional step down station, notionally Northern York TS #1, in addition to incremental loading to bring existing stations up to their full summer LTR, and additional loads associated with electrification of Go Transit. Assuming recommendations to address these needs are put into service, additional needs will begin to emerge in the long term based on two main drivers: Continued incremental load growth associated with an additional new step-down station in Northern York and the potential retirement of York Energy Centre.

Accommodating further step-down stations in Northern York

As described in section 6.3.1.1, ongoing load growth in Northern York Region is expected to trigger the need for new step-down stations roughly every four years (summer peaking) or potentially as often as every three years (assuming high electrified heating and winter growth scenario) in the longer term.

Measures to address near term needs will be sufficient to meet the need for Northern York TS #1, while the assumed location for future Northern York TS #2 is eastward, outside of the electrical system defined as Northern York. Assuming the next station is once again sited in this area, needs should be evaluated on the assumption that additional station loading emerges in roughly the mid 2030s.

Given uncertainty with long-term growth rates, and the risk of sudden, large surges in customer demand from new development or electrification, the local system should be designed to be capable of supplying the full load of this future station, before permitting its connection. The exact nature of needs emerging from this station would depend on its connection location, as well as system changes which may be required to address the potential phase out of YEC.

At a minimum, adding this future station would trigger security needs regardless of whether it is connected on the H82/83V circuits (same protection zone as Vaughan MTS #4, Holland TS, and future Northern York TS #1), or B88/89H circuits (Armitage TS and Brown Hill TS). Seeking exemptions to security needs is not desirable in this area, given the existing operational challenges for managing this system, including maintaining adequate voltage and finding suitable windows for regular outages for maintenance.

Both scenarios, where YEC (or similar-sized generation) would remain in service, or new transmission is added to provide supply from elsewhere in the system, contribute unique challenges to the operation of this system. With the addition of potential security violations, new sectionalization should be considered a mandatory starting point to accommodate a future station. The manner of this sectionalization will ultimately influence the maximum system capability (LMC).

These options are described in more detail in section 7.4.3.4.

Considering a Potential Future without YEC

The York Energy Centre (YEC) currently serves roughly 400 MW of peak summer demand for Northern York, reducing the amount which needs to be supplied into the area from elsewhere. This facility was originally sited in Northern York specifically to offset the need for new transmission and has successfully managed the ability for the area to grow without new transmission since 2012. The contract for YEC is currently set to expire in 2035, and if it is removed from service, would represent an immediate 400 MW shortfall to local capacity to meet the area’s peak demand. This 400 MW shortfall would be in addition to incremental needs from regular customer growth.

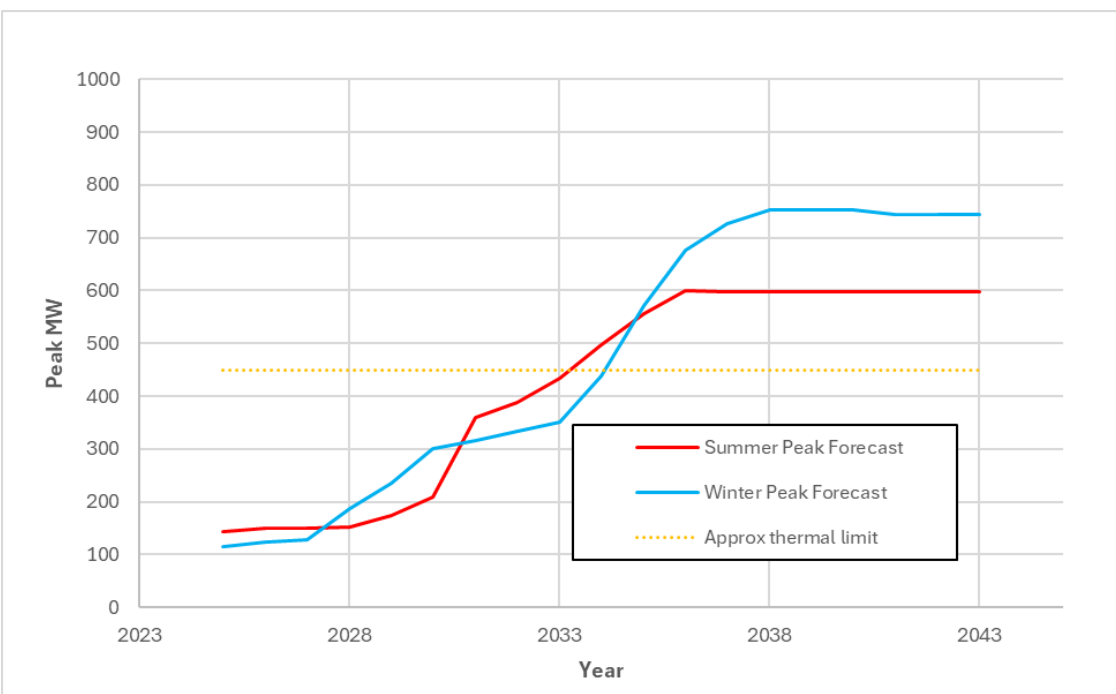
Even after the incremental upgrades recommended in section 7.3.2.2 are implemented, there would be a significant mismatch between local demand and the ability of the system to provide reliable supply. Where options to address near term needs considered measures such as reconductoring, bypassing limiting sections, and NWAs, options to meet needs of 400 MW or more are generally limited to new transmission lines (typically ~600 MW or more of new capacity), or local generation of a similar size and operational characteristics as what had been phased out. These options are explored in greater detail in section 7.4.3.3. If YEC were phased out without a major new supply source, it would severely affect reliability for existing customers and likely limit the ability to connect any incremental load within northern York.

6.3.2.2 Parkway-Buttonville

Capacity needs associated with the Parkway-Buttonville pocket arising in the near term were described in section 6.2.2.2, and emerge along the southern end of the P45/46 circuits, between Parkway TS and Markham MTS #4. In the longer term, demand for additional step-down stations to supply growing loads in Northern Markham, Northern Richmond Hill, and the eastern section of Northern York (including Whitchurch-Stouffville), is expected to further load this corridor. This will trigger similar thermal needs on the remaining northern section of P45/46, between Markham MTS #4 and present-day Buttonville TS. These needs are expected to be triggered when the total load of Buttonville TS, Markham MTS #5, (future) Markham MTS #6, and (future) Northern York TS #2 reach approximately 450 MW, although actual LMC could vary depending on future station, circuit and customer load characteristics. This is in addition to security needs described in section 6.3.3.1, below.

The graph below shows the impact this will have on anticipated need dates for further upgrades, under anticipated summer peak conditions, and a potential higher growth winter peak scenario.

Figure 20 | Circuit loading on northern section of P45/46 circuits (Markham MTS #4 to Buttonville), and thermal limit



Note that total summer load is expected to plateau in the mid to late 2030s, as stations reach their individual LTR, and incremental growth is instead supplied by stations in neighbouring systems. This profile could change if future stations are instead located within this supply pocket.

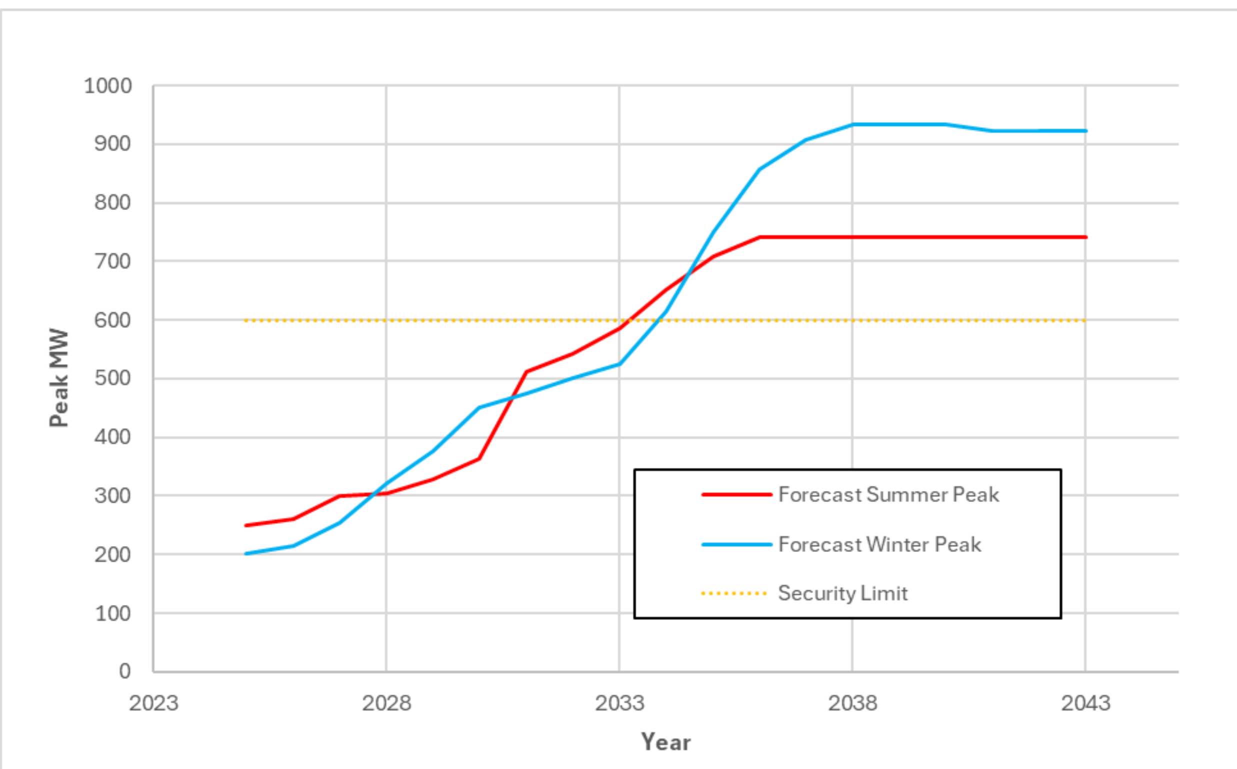
6.3.3 Load Security and Load Restoration Needs

New load security needs have the potential to emerge in the longer term as load growth increases the areas supplying over 600 MW during peak conditions. This becomes more severe when higher growth winter peak scenarios are considered. In many cases, load growth can trigger both capacity needs as well as security needs, with common solution often able to address both. The conditions under which security needs are triggered, and whether they are expected to be addressed through other initiatives, is described below.

6.3.3.1 Markham and Area (Parkway-Buttonville)

The demand forecast for this load pocket load is expected to exceed 600 MW in 2034 (both summer and winter peak forecast) which would violate applicable load security criteria. The graph in Figure 21 below shows the applicable loading, which accounts for all P45/46 connected stations (this is different from Figure 20, above, which only considered load north of Markham MTS #4):

Figure 21 | Full circuit loading on P45/46 circuits, and security limit



This assumes that the need for future step-down stations (either Markham MTS #6 or Northern York TS #2) is triggered, and transmission is available to enable their connection via a Parkway-Buttonville transmission extension. These options are described in sections 7.4.2.1, 7.4.2.2 and 7.4.2.3 and, are preconditions for triggering this security need. Note that this security need is in addition to thermal needs which are triggered in the same approximate time and are described in section 6.3.2.2. Separate solutions are required for each.

6.3.3.2 Kleinburg Radial Tap

The Kleinburg Radial tap refers to the pair of 230 kV circuits, V43 and V44, which span northwest from Claireville TS. These circuits currently supply Woodbridge TS, Vaughan MTS #3, and Kleinburg TS, with plans underway to develop a new step-down station, Vaughan MTS #6, to supply commercial loads in the area. Under normal operating conditions, part of the southern end of this corridor also partially supplies the neighbouring Goreway TS, in Brampton.

Peak demand for the Kleinburg radial pocket is expected to exceed 600 MW in summer 2029, and potentially in winter as soon as 2030. Recommendations to address supply capacity needs for Northern York are expected to address these security needs as well. Details on these proposed solutions are provided in section 7.3.2.2.

6.3.3.3 Parkway-Claireville

Based on the near-term need for an additional station to serve southern Richmond Hill (notionally Richmond Hill MTS #3), and a longer-term need for an additional step-down station to serve southern Vaughan (notionally Vaughan MTS #5), the Parkway to Claireville corridor could potentially be exposed to interruption of approximately 960 MW of peak demand. This would assume all stations are loaded to their LTR, and an N-2 contingency occurring during summer peak. In the event of winter peaks emerging in the longer term, this security risk could approach 1200 MW.

Although the security limit is exceeded today, it is unlikely that a similar exemption would be approved as additional stations seek connection. Load losses of these magnitudes, especially without comparable generation tripped from loss of the same circuits, can introduce significant challenges for balance of supply and demand at the broader bulk level. Updates to applicable security criteria in ORTAC have also introduced a requirement to pursue a permanent solution for load security needs and to only consider exemptions as a temporary measure to avoid delaying the connection of new customer loads.

Near-term recommendation outlined in section 7.3.3.1 are expected to also address this longer-term need.

6.4 Post-2040 System Considerations

Near the end of the planning horizon considered in this IRRP (2040 and beyond), identifying specific needs and developing options to address them becomes more challenging. There is, however, time to study options in subsequent planning cycles.

Understanding needs requires detailed assumptions about anticipated customer demand, seasonal peaks, and hourly profiles on a geographic basis. Given the potential for very high growth rates resulting from electrification, major new large commercial/industrial load centres, in addition to more typical growth rates associated with organic population and employment growth, predicting actual demand this far out cannot be accomplished with sufficient confidence.

The demand forecasts for summer peak, which relies more closely on existing customer behaviour and more modest electrified technology uptake, currently forecasts up to 2,100 MW of demand growth throughout York region over the next 20 years, of which roughly 1,500 MW is accounted for in this IRRP through new step-down stations and associated system upgrades to supply them. If a higher growth winter forecast is used, with more aggressive assumptions related to electrified heating in particular, up to 3,400 MW of demand growth is possible in the same time frame, with approximately 2,200 MW accounted for in this IRRP.

Supplying growth at the higher end of these projections would require greater consideration of the impact on the broader bulk electrical network. Typically, regional planning assumes the bulk system is a static source of power with sufficient ability to supply any required level of local demand. This assumption becomes challenged when considering levels of demand with the potential to affect provincial interface flows, and approach loading limits on what is typically much higher rated bulk equipment. Additionally, a future scenario where extreme demand growth is observed throughout York region would likely mean similar levels of extreme growth are emerging throughout the province, which would trigger the need for significant upgrades on the bulk system as a whole.

The combination of local demand driving bulk system needs, and assumption that bulk upgrades are required throughout the province, means that planning under this long-term high growth scenarios require close coordination between regional and bulk system plans.

Long-term bulk planning is currently underway through the development of the South and Central Bulk Plan, which considers transmission needs out to 2035, in addition to accommodating several planned changes to the provincial supply portfolio. The York IRRP has been carried out in close coordination with this plan, with implications for system assumptions and options available. These points of coordination are highlighted in the following section when options are described in greater detail.

7 Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in York Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included feasibility, cost, lead time, system benefits, and consistency potential options for addressing longer-term needs in the area.

There are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new or reinforce transmission or distribution systems. These are commonly referred to as “wire” options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing infrastructure, 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 certain reliability concerns.
- Install or implement measures to manage the peak demand to maintain loading within the system’s existing LMC. These are commonly referred to as “non-wire” options and can include alternatives such as local utility-scale generation or storage, distributed energy resources (including distribution-connected generation and demand response), or eDSM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wire options. Subsequently, Section 0 to Section 7.4 present the options that were ultimately developed and evaluated to the address near- and longer-term needs, respectively. Opportunities for NWAs are highlighted in their relevant options sections, with additional details provided in section 7.5.

7.1 Options Considered in IRRPs

Both wire and non-wire options are considered in regional planning, although some options may be more suitable for specific need types and characteristics. When evaluating non-wire options such as generation, local distributed energy resources, or energy storage, additional work is required to understand these specific need characteristics, including creation of hourly load profiles, as described in Section 5.7. The suitable technology types and capacities are determined by examining “unserved energy” profiles, representing the hourly demand above the existing LMC. The load profile indicates duration, frequency, magnitude, and total energy associated with each need.

High-level cost estimates for wire options are based on input provided by the transmitter and transmission benchmark costs. In contrast, cost estimates for non-wire options are based on benchmark capital and operating cost characteristics for each resource type and size. Due to policy considerations and decarbonization efforts, new natural gas-fired generation was not considered as a generation option for local needs identified by the regional plan. Energy storage, solar generation, and wind generation were considered for generation options.

New eDSM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this framework and the new 2025-2036 framework, the IESO has flexibility to deliver new programs or offer regional incentive adders for existing province-wide programs to help address regional and/or local 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. NWA considerations are discussed further in Section 7.2, as part of the screening of options that was conducted. (previously "CDM Guidelines") to leverage distribution rates to help address distribution and transmission system needs using non-wire alternatives. At time of IRRP publication, the Ontario Energy Board is currently considering a proposal from the IESO and the Local Distribution Company community to enhance this existing mechanism to better enable IESO-LDC collaboration and co-funding of eDSM initiatives that provide both local and provincial system benefits. NWA considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

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 2025 CAD for this report) of these levelized costs is the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around cost estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The transmitter-led RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine cost estimates of wire options before implementation work begins. Costs are typically further refined over the course of project development work. The IESO continues to participate in the Technical Working Group during the RIP and will revisit a recommendation if estimates change significantly. Furthermore, smaller scale demonstration projects can be explored in cases where other barriers (e.g., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options following the completion of the IRRP.

The list of assumptions made in the economic analysis is found in Appendix F.

7.2 Screening Options

As described in the previous section, an array of options is developed to meet identified needs during an IRRP, and each option is then evaluated to determine which are feasible and successfully address all needs. Final recommendations are typically made for those which are the most cost effective, although increasingly a wider range of factors are considered, including community preferences, flexibility, or providing some degree of reliability and demand forecast uncertainty risk mitigation. This process is complemented by stakeholder engagement and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options 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 22 and further discussed in the next sections for the identified needs.

More details on the steps and inputs used in the screening mechanism can be found in Appendix C, and a summary of the options screening results for York Region is provided in Table 7**Error! Reference source not found.** for station capacity needs, and in Table 8| for supply capacity needs.

Figure 22|IRRP NWAs Screening Mechanism

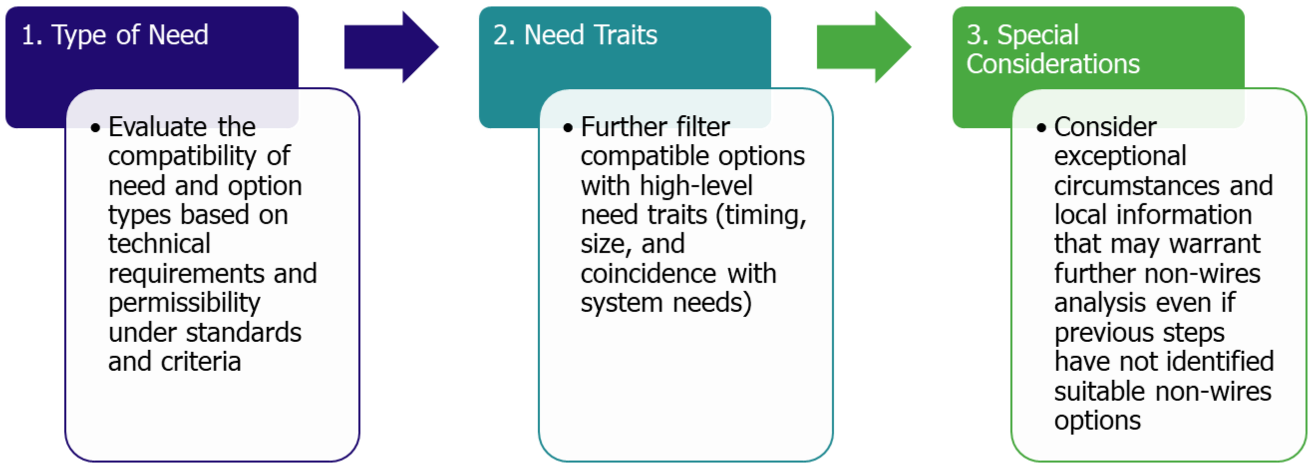


Table 7| Options Screening Results for Station Capacity Needs

Need	Screened In	Screened Out
Station Capacity: All Subregions	• Operational measures • eDSM • Distributed generation • Wires options	• Demand response – due to magnitude and timing of need

Table 8| Options Screening Results for Supply Capacity Needs

Need	Screened In	Screened Out
Supply Capacity: Parkway TS to Buttonville TS Claireville TS to Brown Hill TS	• Operational measures • eDSM • Distributed generation • Transmission-connected generation • Wires options	• Demand response – due to magnitude and timing of need

7.3 Options and Recommendations for Addressing Near-Term Needs

The following sections describe recommendations for addressing near-term needs. Unless stated otherwise, implementation is recommended to proceed immediately to ensure upgrades can be in place to address expected need dates. Where options are not expected to be in place in time, alternative measures have been highlighted to help address short term needs.

7.3.1 Options for Addressing Station Capacity Needs

The need for three step-down stations has been identified in the near term. Work should continue to identify and secure appropriate land and proceed with station development.

7.3.1.1 Northern York TS #1

The need for a new step-down station to serve growing customer demand in Northern York Region is immediate. However, the timeline for design, approval, and construction of this type of infrastructure typically spans around 4-5 years. As a result, this station is not expected to come into service any earlier than 2029.

Several approaches are recommended in the interim to manage growing customer demands before the infrastructure solution can come into service:

1. Additional electricity demand side management should be targeted in northern York region, to assist in ensuring some capacity remains available for growth of existing customer loads. Additionally, lowering peak demand through incremental eDSM would reduce the risk of Load Rejection in the event of an outage during peak load conditions, thereby improving customer reliability. Programming targeting the areas of Newmarket, Aurora, East Gwillimbury, and West Gwillimbury would be the most effective at deferring these step-down station needs.
2. Hydro One Distribution is investigating options to transfer additional loads at the boundary between the Holland TS/Armitage TS service territory and neighbouring Brown Hill TS service territory. Although large scale transfers are unlikely to be feasible given the distances between these stations, small service territory adjustments at the boundary may be effective to manage growth in the near term and still provide longer term reliability benefit due to enhanced restoration capability. Enhancing restoration capability ensures this interim measure remains cost effective by providing enduring customer benefit, even once the future station comes into service.
3. New, load connections have to seek connection through other Northern York stations with remaining capacity. It should be noted, however, that this may incur larger distribution related costs as new feeder lines may be required to cover long distances. The nearest step-down station with significant remaining or unallocated capacity is Brown Hill TS, which is located approximately 15 km northeast from the preferred location of Northern York TS #1. Until connection costs are brought down with a nearer connection point, this may delay Northern York’s ability to connect new large load customers.

Based on existing loads and near-term demand forecast, it is recommended that Hydro One proceed with the acquisition of land, the design, and the construction of a new step-down station by 2029 to serve Northern York Region, in the vicinity the Holland TS area. Typical development costs for these types of stations, including real estate, are generally $60 Million[6].

For the purposes of this study, the new step-down station was modelled as connecting to the H82/83V circuits, which exacerbates the existing supply needs for this corridor, as described in section 6.2.2.1. Measures to address these needs are described and recommendations made in section 7.3.2.2. Timelines to address these needs should not interfere with the immediate development of the step-down station, as incremental needs can be met on an interim basis through the arming of load rejection through the existing Remedial Action Scheme (RAS) for Northern York Region.

7.3.1.2 Markham MTS #5

Based on existing peak demand and forecast near-term growth, the need for the next Markham area station is anticipated by 2029. Alectra has identified a suitable location for the next Markham MTS #5, and this project is currently under development. Based on recommendation from the previous IRRP, Markham MTS #5 is planned for connection near the existing Buttonville TS, supplied from the P45/46 circuits. The expected in-service date of this station is 2028-2029. Typical development costs for these types of stations, including real estate, are generally $60 Million. Supplying the full rated capacity of this station and the existing Buttonville TS and Markham MTS #4 will require supply capacity increases to the southern section of P45/46 circuits, further described in section 7.3.2.3.

7.3.1.3 Richmond Hill MTS #3

As described in section 6.2.1.3, significant development pressure in the vicinity of the Richmond Hill Centre Urban Growth Centre will require additional step-down station capacity by 2030 to reliably supply new and intensified customer demand. The area of intensification to be supplied by this new station is roughly bounded by Yonge St to the west, Steeles Ave to the south, 16th Ave to the north and Leslie St to the east. Alectra has identified a suitable location for the next step-down station to supply this forecasted growth, Richmond Hill MTS #3, which is currently under development. The proposed connection point will be along the V71/75V circuits, near the existing Richmond Hill MTS #1 and #2. The expected in-service date of this station is 2030. Typical development costs for these types of stations, including real estate, are generally $60 Million.

Once connected, loading up this new station will exacerbate existing security needs along the corridor. Although an exemption to security criteria is in place today, continued load growth on this corridor, as anticipated through the connection of Richmond Hill MTS #3 in the near term and Vaughan MTS #5 in the longer term, will require a wires solution to be put in place to address security needs. This is further described in section 7.3.3.1.

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[6] Actual costs can vary depending on factors such as land costs and equipment ratings

7.3.2 Options for Addressing Supply Capacity Needs

In some cases, measures to address capacity needs will also have the benefit of addressing security needs. Where a proposed solution addresses both sets of needs, it is discussed in the sections below.

7.3.2.1 York Energy Centre Station Service

When operating, the York Energy Centre (YEC) injects power through its transmission connection point along the B88/89H circuits. However, the station service (power used to run station equipment), is normally supplied through a distribution connection from Holland TS, which is connected to the H82/83V circuits to the south of YEC. These two sets of circuits, B88/89H and H82/83V, are connected through a set of breakers that were installed in 2017, several years after YEC came into service. This created a condition where the loss of H82/83V will remove Holland TS, and subsequently YEC, from service without interrupting supply to B88/89H. This creates potential capacity and voltage related needs for the local system (described in section 6.2.2.1), which would not be as severe if YEC remained in service.

Changing the station supply arrangement for YEC would allow for YEC to remain operational under the loss of H82/83V, and the loss of the T1B breaker at Holland TS (current worst-case N-2 contingency). The impact of resolving the YEC station service issue would result in an increase of approximately 90MW in the LMC from the worst-case contingency.

There are different potential ways in which YEC station service could be addressed including:

- Installing second step-down transformer via the B89H tap point, allowing for station service to be drawn under regular operating conditions from B89H as well as the existing supply available from B88H, or;
- Installing a potential automatic station service transfer arrangement to allow for automatic transfer between the Holland TS distribution service and B88H supply points during a contingency.

The ultimate preferred service arrangement should be determined based on deeper engineering study of the cost and technical feasibility of different possible arrangements. It is recommended that the station owner work with the connecting transmitter, Hydro One, to identify and implement this system upgrade. The final configuration should allow for uninterrupted operation of YEC under all applicable N-1 and N-2 transmission planning contingencies affecting H82/83V, as well as all N-1 contingencies affecting either B88H or B89H.

Although cost estimates for this upgrade are not yet available, alternatives to provide to similar level of reliability would be orders of magnitude more costly and disruptive than the proposed station service work, and either require new transmission to create redundant supply paths into the area, or the construction of a similar sized generation facility (~400 MW) to provide redundant supply. By contrast, all anticipated upgrade options could be accommodated entirely within the existing station boundary.

In addition to improving reliability for the local area, this will allow YEC to remain operational under a wider range of system conditions, which in turn improves power and ancillary service availability for the province as a whole.

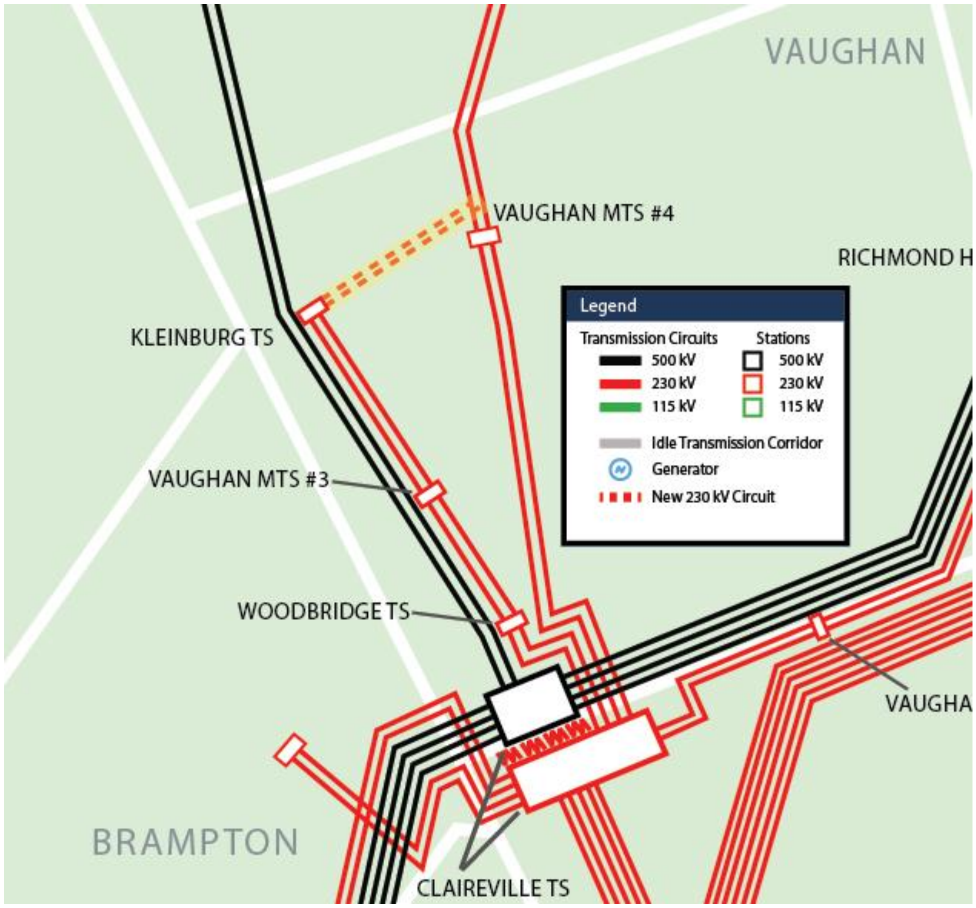
Consideration of new regulatory or contractual mechanisms may be required to finance this type of system upgrade. There is no existing mechanism for costs incurred by the station owner to be reimbursed, and it also does not fit within the existing competitive procurement streams.

Addressing this station service issue will have an immediate benefit to local customer reliability by lowering exposure to Load Rejection (LR) events, and allowing the local system to accommodate some of the additional load growth associated with the connection and loading of Northern York TS #1. Additional technical details of this analysis are included in Appendix E.

7.3.2.2 Kleinburg-Kirby Transmission Link

After addressing the York Energy Centre (YEC) station service issue (see section, 7.3.2.1), the next most limiting contingency affecting Northern York is triggered by thermal violations of the southernmost section of circuits H82/83V, which span from Claireville TS to Vaughan MTS #4. Due to a narrow transmission corridor, and close proximity to development along this route, this section is not a good candidate for reconductoring to increase capacity of the line. Instead, a new transmission route is proposed to bypass this limiting section and improve supply capacity into Northern York. This new transmission line, referred to as the Kleinburg – Kirby Transmission Link, would create a connection between the existing Kleinburg radial tap, and connect to a point north of the exiting Vaughan MTS #4. The notional location of the facilities is shown in Figure 23.

Figure 23| Potential Kleinburg – Kirby location



Creating this bypass would reduce the amount of power that would have to flow north from Claireville TS to Vaughan MTS #4 to reach stations further to the north. The impact on LMC depends on where new stations are ultimately located in Northern York, and the balance of demand between them, however this upgrade is expected to allow for the connection and full loading of Northern York TS #1.

The long-term need for this corridor to supply Northern York, as well as northern Peel and Halton regions, had previously been identified through the regional planning process. Additionally, the Ministry of Transportation (MTO), dealing with similar growth and intensification needs from a transportation perspective, has been working to develop the proposed Highway 413 in the same general area. More information on MTO's process is available on the project website, linked here. In accordance with the Provincial Policy Statement, which recognizes the value of co-locating linear infrastructure from a land use perspective, the IESO and Ministry of Energy and Mines have been working for over a decade to identify and preserve land in the same general vicinity as the proposed highway. This new transmission corridor would roughly parallel Highway 413, with minor deviations where required to connect with specific transmission supply points or avoid areas unsuitable for transmission. The final route, when fully built, would provide a transmission route connecting a future Milton TS to Kleinburg TS. This line would connect with the extension further east to the H82/83V circuits in Vaughan, at a point north of Vaughan MTS #4, close to the intersection of Kipling and Kirby Rd. This proposed transmission line is referred to as the Kleinburg to Kirby link.

As an initial configuration, a double-circuit 230 kV is envisioned along this route. In the longer term, a second double-circuit line could potentially be required to further reinforce and create a separate redundant supply path to serve the southern sections of H82/83V, if additional step-down stations are required in the vicinity of the existing Vaughan MTS #4. The initial 6 km double-circuit 230 kV Kleinburg to Kirby link is estimated to cost $40 million and would likely take 6-7 years from project initiation until in service date (timelines aligned with Bulk Kleinburg TS build out, described in section 8.1). This assumes a steel lattice tower design and does not account for any additional land costs.

7.3.2.3 Reconductoring P45/46

As described in section 6.3.2.2, thermal limits of the existing P45/46 circuits are expected to be exceeded following the loss of the companion circuit when total loading on the stations supplied by these circuits (Markham MTS #4, Buttonville TS, and the future Markham MTS #5) exceeds approximately 450 MW.

Based on a review by Hydro One, it is technically feasible to upgrade the limiting conductors along this transmission corridor. Reconductoring the section between Parkway TS and Markham MTS #4 would allow the P45/46 corridor to support the full LTR at Markham MTS #4, Buttonville TS, and the future Markham MTS #5. The estimated cost would be $4.3 million.

Based on current forecasts, the need date for this upgrade is approximately 2031. However, there is value in advancing this work to coincide with the planned in-service date of Markham MTS #5 (2028-2029) for two reasons. First, once connected, there may be value in utilizing new step-down station assets at a quicker rate, such as when transferring loads during an outage on a neighbouring station, or to make more efficient use of distribution assets closer to actual customer loads. For that reason, it may not be efficient to curtail load at this station once it is connected. The second reason deals with operational and logistic challenges of managing reconductoring work. Typically, one of the conductors being upgraded would need to be taken out of service for long periods of time, limiting supply capacity of the system for weeks, or even months at a time. This timing of work will need to be carefully planned to coincide with periods of time when demand is expected to be lower. However, the longer the work is delayed, the more challenging it can be to carry out, as available windows for taking these types of long outages become shorter.

Hydro One, with the IESO, should determine a preferred window for carrying out this work as part of the RIP process.

7.3.3 Options for Addressing Load Security Needs

The sections below describe preferred solutions to address load security needs. In the past, LDCs and transmitters have had the option of jointly applying for exemptions to security criteria, where the cost of upgrades is expected to exceed customer benefit. Although the IESO has typically granted these exemptions, revisions to applicable criteria now only permit exemptions as a temporary, or stop gap measure, where longer term solutions may take additional time to implement.

7.3.3.1 V71/75P Circuit Breakers

As described in sections 6.2.1.3 and 6.3.1.3, security limits are exceeded along the V71/75P circuits today, and this is expected to worsen once Richmond Hill MTS #3 connects, and in the longer term Vaughan MTS #5. Although an exemption to security criteria is in place today, it is not anticipated that it will continue to apply as revisions to security criteria now require longer term plans to address needs to be in place. Additionally, the scale of the security need has surpassed 730 MW during the most recent 2025 summer peak, and rapid anticipated load growth from new stations on the corridor is (linked to existing urban development plans). As a result, there is an immediate need to address load security for stations supplied by these circuits.

Existing switching facilities along this corridor allow for the partial restoration of load following the loss of two transmission elements, but they do not prevent the full load along the corridor from being lost immediately following a double contingency affecting both circuits. By adding inline breakers near the midpoint of the V71/75P circuits, a contingency affecting both circuits would only cause the loss of roughly half of the connected stations, significantly reducing the amount of load interrupted. The exact amount of load lost would depend both on the placement of the breakers, and the future connection points of Richmond Hill MTS #3 and Vaughan MTS #5. A suitable location for these breakers would be one where the simultaneous loss of the V71/75P circuits at a single point along the corridor (i.e., a credible common tower contingency) would not interrupt more than 600 MW of load.

Given the proposed connection point for Richmond Hill MTS #3, one notional option would be to locate these breakers along the 6 km stretch between present day Vaughan MTS #1, and Richmond Hill MTS #1. When Richmond Hill MTS #3 is connected, and all six stations on the corridor are fully loaded to their summer LTRs, this would expose a maximum of 459 MW to interruption for a common tower double-circuit contingency. Assuming the future Vaughan MTS #5 is connected east of these breakers, along the same section as the Richmond Hill MTSs #1, #2, and #3, the longer-term maximum interruptible load would be 560 MW, still within acceptable security limits. An ideal location for these breakers would therefore be between present day Vaughan MTS #1 and the future Vaughan MTS #5.

Identifying the exact location for the future breakers will require detailed review of the existing transmission corridor, both to find an area where they can be accommodated without requiring additional land acquisition and ensure development work can be undertaken without disrupting operation of any existing facilities. The Working Group recommends that Hydro One identify a preferred location for connecting in line breakers along V71/75P within the scope of the upcoming York RIP and then proceed to implement this project. Typical costs for this type of infrastructure range from $30 million to 35 million and take approximately three to four years to develop. As the V71/75P circuits are owned and operated by Hydro One, it is not a suitable candidate for competitive procurement.

7.4 Options for Longer-Term Needs

Longer term options to address needs throughout York Region will be informed by actual demand growth, location of future step-down stations, and longer-term local generation supply availability. The following sections describe potential outcomes based on best available estimates of how these factors will evolve. Unless stated specifically, actions are generally not required at this time, unless it is to preserve longer term options.

7.4.1 Options to Address Southern Vaughan, Richmond Hill, and Markham Needs

The area served by stations connected to the V71/75P circuits roughly aligns with Southern Vaughan, Richmond Hill, and Markham. Security needs exist today, though are managed through exemptions to applicable criteria. Longer-term needs and options are linked to ongoing customer growth, intensification, and managing security needs as they worsen when new step-down stations connect.

7.4.1.1 Vaughan MTS #5

The longer-term need for a new step-down station to supply southern Vaughan is described in section 6.3.1.3. The preferred location for future connection would be in the vicinity of Vaughan Metropolitan Centre (VMC), which is easily accessible from connection points along the V71/75P circuits. Although security limits are already exceeded along this corridor today, the ideal location of these circuits make any other connection point for a station intended to supply VMC impractical. Instead, Vaughan MTS #5 is recommended for connection along V71/75P, and measures to address outstanding and worsening security needs will be explored separately. Near-term recommendations for addressing security needs have considered the anticipated longer-term impact of connecting this step-down station. Details on recommendations to address security needs are provided in section 7.3.3.1.

The need date for Vaughan MTS #5 is linked to growth within the VMC pocket, and not to overall capacity at remaining southern York stations. Alectra has indicated that they are working towards a 2033 in service date, based on connection applications and approved municipal plans. Actual need date may vary depending on develop timelines for new customers in the area. Although the need date is outside of the five-year near-term window, work should continue towards this targeted completion date. Typical development costs for these types of stations, including real estate, are generally $60 million.

7.4.2 Options to Address Northern Markham, Richmond Hill, and Whitchurch-Stouffville Needs

The areas of northern Markham and Richmond Hill, in addition to eastern sections of Northern York, currently have limiting step down station capacity due to their long distances from the existing transmission network. As urban boundaries continue to expand northward, and rural loads intensify, this will trigger the need for new transmission stations, and transmission infrastructure to supply them. Individual options and their timing are described below.

7.4.2.1 Northern York TS #2

As described in section 6.3.1.1, the preferred location for the future Northern York TS #2 would be in closer proximity to growing load centres in the eastern half of Northern York. Whitchurch-Stouffville has been identified as a particularly challenging area for meeting long term distribution connection requests as it is expected to see significant load growth over the coming 20 years, and is also far removed from existing transmission infrastructure. Supplying customer loads, especially denser demand from high electricity use customers or more urban/suburban development, becomes more challenging for distribution networks the further they are from the transmission supply point. This can result in more expensive connections, and poor customer reliability.

Additionally, the most recent step-down stations built to supply Northern York (Holland TS and Northern York TS #1) have been or will be built in the same general area in western Northern York, with connection to the same supplying circuits. Diversifying the location of step-down stations provides benefit to customer reliability by allowing alternate supply paths through the distribution network to manage planned or emergency outage conditions.

An ideal location for Northern York TS #2 would therefore be close to the eastern sections of Northern York. No transmission infrastructure currently exists in this area, which means triggering development of this step-down station will also require development of new transmission to supply the station. Typical development costs for these types of stations, including real estate, are generally $60 million.

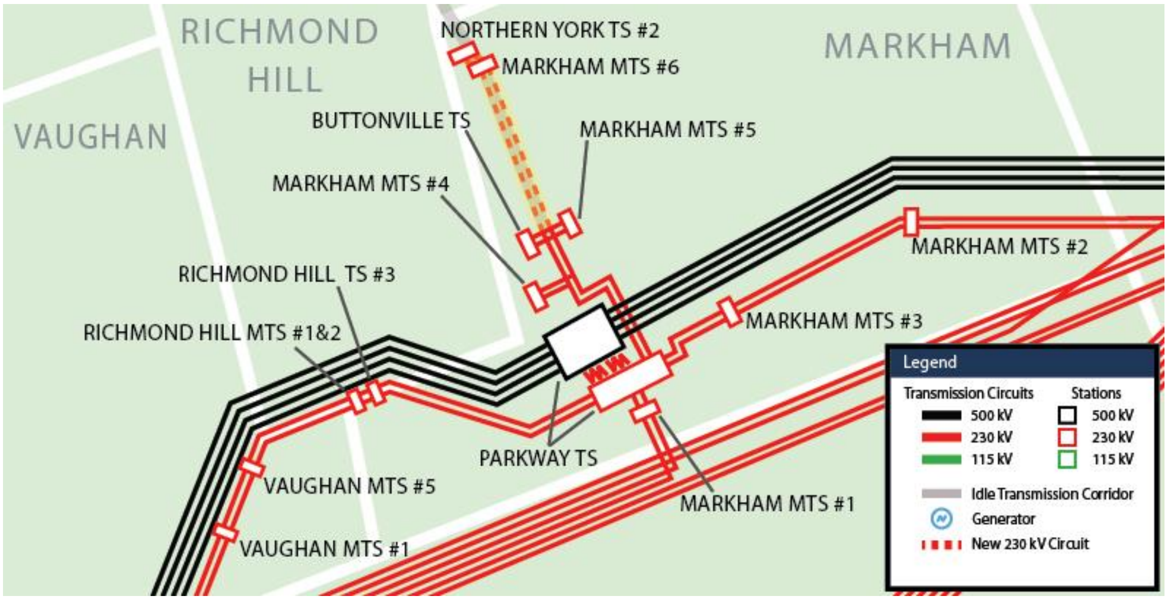
7.4.2.2 Markham MTS #6

As described in section 6.3.1.2 continued urban expansion throughout northern Markham and Richmond Hill is expected to trigger the need for a new step-down station in around 2034. Actual need date could vary depending on actual demand growth in the area, which is influenced both by new as well as intensified customer demand, but also by the successful uptake of NWA where it can offset peak demand growth. Because the driver for this station is growth in the northern section of these municipalities, and because transmission does not currently extend beyond ~3km from the south of Markham, this station could not be built in a way that allows for efficient or reliable service to customers today. As a result, pursuing the development of this future step-down station will also require a parallel development of new transmission to allow connection closer to anticipated load centres. An existing, idle transmission corridor already exists in a suitable area and could be leveraged to enable this connection. This is explored in section 7.4.2.3, below. Typical development costs for these types of stations, including real estate, are generally $60 million.

7.4.2.3 P45/46 Transmission Extension

As described above, connecting and supplying the future Northern York TS #2 and Markham MTS #6 in the longer term will require extending the existing transmission system a further 7 km (approximately) into northern Markham. An idle transmission corridor already exists and can be repurposed for new infrastructure without requiring new land acquisitions. The existing towers and conductors, rated for 115 kV, would need to be rebuilt to a 230 kV standard. The location of the idle transmission corridor and the general location of future step-down stations are shown in Figure 24.

Figure 24| P45/46 transmission circuit extension into northern Markham



Alternative connection points for the future Northern York TS #2 and Markham MTS #6 stations would require either developing new transmission rights-of-way to supply the emerging load in northern Markham or locating the new station capacity along the existing transmission, which would be far from the anticipated growth. Neither of these alternatives are preferred to repurposing the idle transmission corridor. New transmission corridors through heavily built-up areas would be significantly more costly and disruptive to the community. Alternatively, locating new step-down stations farther away from the load would require long distance distribution lines and would introduce reliability risks and potential voltage support challenges due to the load density and distance from the transmission supply.

Based on comments received through engagement, there is a strong local preference for deferring the need for new transmission infrastructure in Markham for as long as possible, and for considering less visually intrusive technology types when the transmission is ultimately required.

The need for new transmission is directly linked to the need for new step-down transmission stations to serve Markham, northern Richmond Hill, and the eastern half of Northern York region. Measures that target peak demand reductions in these areas could have deferral benefits pushing the need for these stations and consequential transmission expansion. As a result, it is recommended that NWAs be targeted in this area, with particular focus on Markham, parts of northern Richmond Hill (i.e., in areas not associated with intensification along Highway 407 and Yonge subway extension), Aurora, and Whitchurch-Stouffville. These initiatives could produce net positive economic benefits by deferring infrastructure needs. The combined station development costs, including real estate, are estimated at approximately $120 million, while the minimum transmission cost is estimated at $45.5 million, and costs could be higher depending on the transmission technology type (e.g., monopole towers or undergrounding).

Should the transmission expansion be required to supply growth in northern Markham, there are technology types that can be considered at the time of designing the facilities to reduce the potential visual impact. For example, steel monopole tower designs, although more expensive than lattice tower structures, can be used in urban areas to minimize foundations and leaves more space for secondary uses. These alternative tower types may also be preferred by neighbouring communities due to their less industrial aesthetic. Underground transmission may also be preferred by communities, but undergrounding is generally reserved for cases where overhead facilities are not technically feasible due to their very high costs. Underground transmission cables can be several times more expensive than overhead lines, with the incremental cost related to undergrounding likely borne by the benefitting community. Other trade-offs associated with underground cables are a lower asset life expectancy, and longer and costlier repair and maintenance. Cables are less likely to experience outages due to factors such as weather, animal contact, and vehicular accidents, but may be more prone to impact from overland flooding or drought conditions. Given that this transmission corridor would be supplying radial loads (i.e., no redundant supply from both ends), interruption to customer loads could be significant if a contingency impacted an underground cable. A comparison of overhead and underground technologies for this transmission is provided in Table 9.

Table 9| Estimated cost of ~7km transmission extension along existing Right of Way in Markham

	Life of Asset (Years)	Cost ($M)
Lattice Tower	90-100	45.5
Cable	40-50	175

Decisions for the final technology type of new transmission lines are not typically made until the Environmental Assessment (EA) stage of line design.

7.4.2.4 P45/46 reconductoring to Buttonville

The near-term recommendation to reconductor the limiting section of P45/46 circuits (described in section 7.3.2.3) only considered the need to reconductor the section between Parkway TS and Markham MTS #4. This upgrade would allow for the full loading up to station LTR of Markham MTS #4, Buttonville TS, and future Markham MTS #5. In the longer-term, step-down station needs are expected to trigger the extension of circuits P45/46 and connection of two additional step-down stations: Northern York TS #2 and Markham MTS #6. The collective load of these five step-down stations would exceed both security limits and supply meeting (thermal) capacity of the remaining P45/46 circuits section between present day Markham MTS #4 and Buttonville TS. Options to address security needs are described in section 7.4.2.5, below.

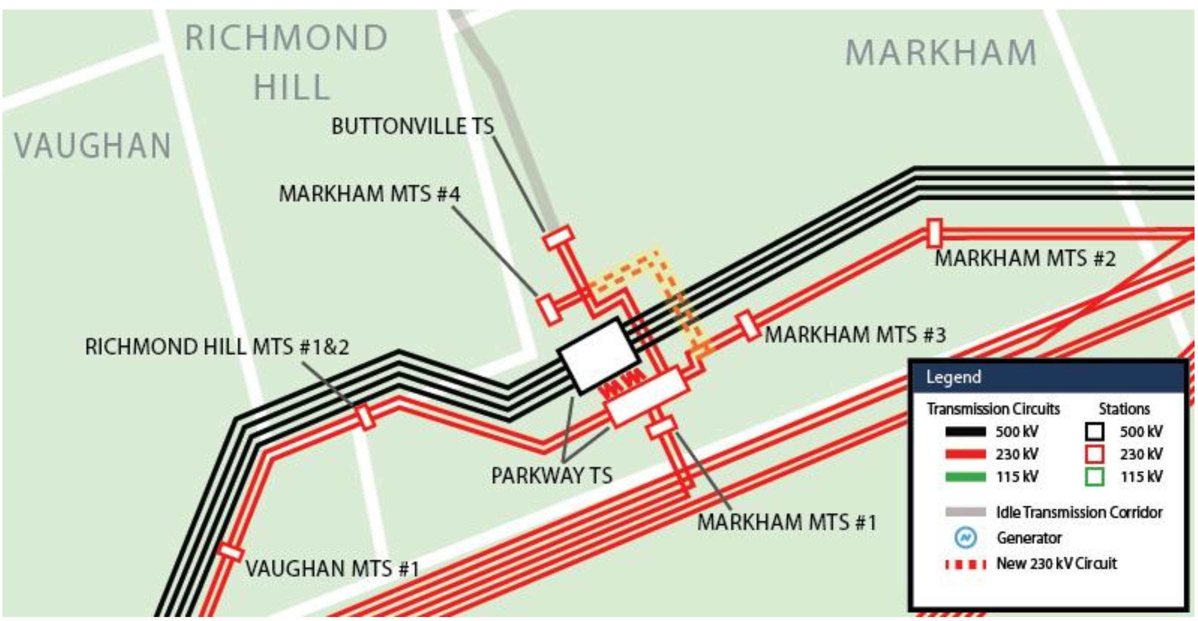
Thermal needs would be triggered when combined load at Buttonville TS, Markham MTS #5, Markham MTS #6, and Northern York TS #2 exceeds approximately 450 MW. These needs can be addressed by reconductoring the remaining ~2.7 km section of P45/46 circuits between Markham MTS #4 and Buttonville TS, with an approximate cost of $9.5 million.

The need date for this reconductoring work is when the collective load of Buttonville TS, Markham MTS #5, Markham MTS #6, and Northern York TS #2 exceeds 450 MW. To ensure that newly connected stations can make full use of their assets, this work should occur no later than the connection of either Markham MTS #6 or Northern York #2 TS, whichever comes first. However, it can often be challenging for facility owners and operators to manage outages required during reconductoring work. As a result, this work may be advanced at Hydro One's discretion, particularly if project efficiencies are identified from pairing this work with the reconductoring of the adjacent Parkway TS to Markham MTS #4 section of P45/46.

7.4.2.5 Markham MTS #4 radial tap

After addressing thermal needs with the reconductoring described above, the connection and loading of longer-term stations to the P45/46 circuits would still cause security needs to emerge when total load exceeds 600 MW. To address security needs, a new radial transmission circuit could be extended from the existing transmission corridor in the south (adjacent to Highway 407), to connect Markham MTS #4, and remove it from the remaining P45/46 circuits. This would increase the LMC of the area by roughly one station worth of load. This is shown conceptually in Figure 25.

Figure 25| Possible Radial Tap of Markham MTS #4

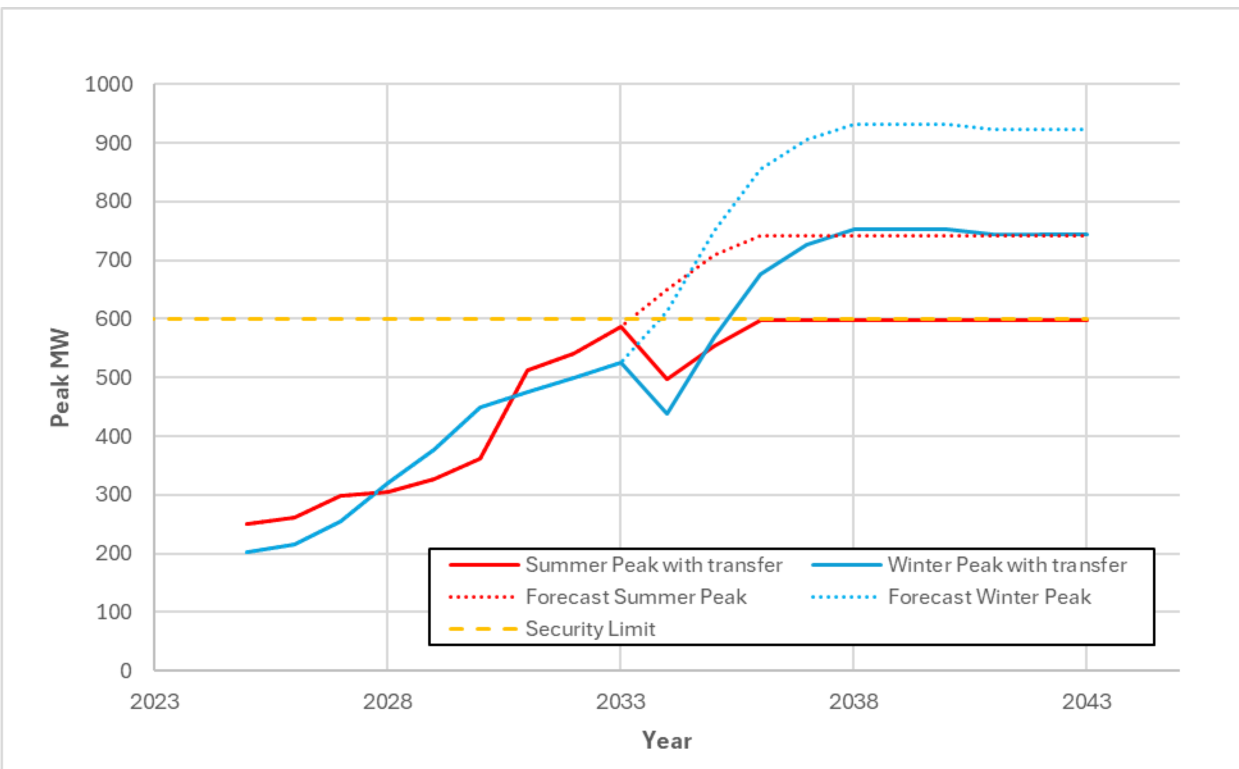


Markham MTS #4 is the preferred station for tapping off with a new transmission connection, as it is located close to alternate transmission points, with potentially as little as 1.5 km of new transmission required. Several potential connection points for this extension exist, including direct connection to Parkway TS, and tapping of the existing C35/36P circuits. The latter option is currently preferred as it would be significantly less costly than a connection within Parkway TS, which would incur additional upgrade costs to existing bulk system infrastructure at the station due to space constraints. The estimated present-day cost of the Markham MTS #4 tap from C35/36P circuits is $9 million. Making a direct connection within Parkway TS, while offering improved reliability by reducing the number of stations served by a single transmission asset, would likely incur a minimum additional cost of $70 million to upgrade existing Air Insulated Switchgear (AIS) to Gas Insulated Switchgear (GIS). Both candidate transmission connection points can be accommodated within existing transmission corridor right of ways.

It is recommended that this work be undertaken to coincide with the connection of either Markham MTS #6 or Northern York TS #2, whichever is ultimately required first. This will allow LDCs to make full use of connection facilities once they become available. Identification of a preferred connection point for the Markham MTS #4 radial tap should be reevaluated during the next planning cycle, as development work is not expected to be required within the next 5 years. Cost assumptions related to different connection points may change in the interim based on bulk planning outcomes and/or upgrades required for new customer connections. This also provides time to monitor demand growth, and to implement measures aimed at managing the demand growth in order to defer the need for new infrastructure as long as possible.

Figure 26 shows the impact of removing Markham MTS #4 from the P45/46 circuits (notionally shown in year 2034) enables the remaining stations to be loaded up to the forecast summer peak.

Figure 26| P45/46 Circuit Loading



In the event that higher winter peaks begin to emerge in the long term, violations of security criteria are possible, with peaks potentially reaching 740 MW. If forecast winter peaks begin to emerge, NWA may provide a good solution to address periods of time where there is a risk of exceeding security limits, particularly as resources would only be required for short periods of time over the year.

7.4.3 Options to Address Northern York Needs

Preferred options to address longer term needs in Northern York will ultimately depend on the location of future Northern York step down stations, and whether YEC is assumed to continue commercial operation after 2035. Potential options are described below, although actions will not need to be taken to advance solutions at this time.

7.4.3.1 Northern York TS #3

As outlined in section 6.3.1.1, by the mid 2030s, growth rates in Northern York are expected to require a new step-down station to serve growing customer demands approximately every 4 years. This could further increase if large loads associated with major customer connections begin to emerge. The general preferred location for Northern York TS #1 and #2 has already been identified based on existing capacity limitations and anticipated high growth areas (the general vicinity of Holland TS and future Markham MTS #6, respectively). The preferred location for Northern York TS #3 is not yet known but would likely be in the general vicinity of Holland Marsh junction, where it would be located to accommodate growth throughout the communities of King, Newmarket, East Gwillimbury, and Bradford West Gwillimbury. This is because these communities are the furthest from the planned location of Northern York TS #2, so, as with Southern York region today, it is reasonable to assume alternating new stations between the east and west sides of the Northern York area.

An existing, idle transmission corridor currently stretches from the Holland Marsh junction, northwest through Bradford-West Gwillimbury, and ultimately through Simcoe County to connect with the existing Barrie TS and planned Innisfil TS (stations are within the South Georgian Bay/Muskoka regional planning area).

Figure 27| Conceptual route along idle corridor between Essa TS and Holland Marsh JCT

Making use of this corridor should be evaluated closer to the Northern York TS #3 need date to determine if the incremental benefit of providing step down capacity closer to load growth centres would offset the increased transmission cost. These benefits could include lower distribution infrastructure costs, lower connection costs for large customers, and higher reliability and power quality depending on the future areas of highest demand growth. Having this station on a separate transmission radial link could also potentially improve future capacity constraints on the remaining network circuits in Northern York (H82/93V and B88/89H), but this would need to be evaluated when actual longer-term supply and demand conditions are better known.

7.4.3.2 York Energy Centre Continued Operation

As described in section 6.3.2.1, the phase out of YEC following its contract expiry in 2035 would introduce a sudden 400 MW shortfall of local capacity in Northern York region. The supply gap would be in addition to organic load growth already defined in the load forecast. Meeting a sudden supply requirement of this magnitude would either require similar sized generation to take its place, or new transmission to bring capacity into he same general area where generation is lost.

In order to replace the existing, single cycle gas supply, a generation option would need to have similar operational characteristics as YEC today. This means the ability to rapidly ramp up operation, adjust generation levels to match local demand levels, and operate continuously throughout periods of peak demand, which can last for several hours in a day, and last several days in a row. Intermittent generation sources, such as solar and wind, would not be suitable alternatives due to significant land requirements to account for lower capacity factors for these generation types. Pairing with batteries would also pose challenges, as the size of batteries required would need to account for worst expected duration of needs over several years, which would not be economic since these conditions are by definition rare events.

It is important to note the that the local requirements to operate YEC (or a similar sized and technology type resource) are only triggered for short periods of the year. This would include hours where local demand is at its highest, or during planned or emergency system outages. While fully offsetting the need for the full 400 MW of available capacity would be very challenging without significant transmission infrastructure to replace this shortfall, adding additional energy sources, such as a Battery Energy Storage System (BESS), would lower the number of hours of the year in which YEC would be expected to operate.

Local communities have consistently indicated a strong preference for lowering greenhouse gases (GHG) emissions released in the area, where achievable with minimal disruption to the surrounding agricultural land use. Capital Power, the owner of YEC, has recently installed a 132 MW BESS to one of the two yards that YEC operates out of. The existing BESS, while able to lower expected GHG from normal operation, does not have a significant impact on local capacity or reliability needs.

If a second, similarly sized BESS were connected to the B89H circuit (either at YEC, or elsewhere on the circuit section), the combined impact of the two BESS units would improve system reliability performance, as at least one could be assumed in service under all contingencies in which either B88H or B89H remain operable. The reliability benefit for adding a second, identically sized BESS within the B89H corridor would be equivalent to approximately 60 MW of reliable local capacity, after accounting for typical operational profiles of BESS technology.

However, the supply capacity increase from this second BESS would not be sufficient to offset near term needs, nor would it have an impact on longer-term step-down station capacity needs. For that reason, it is not included as a recommendation in this study. A combination of short circuit and congestion issues also currently prevent new local resources, including BESSs, from connecting in this area. However, if these issues are resolved in the longer term, this project, or other similar sized generation projects, could help defer longer term needs in the area while reducing the amount of time YEC could be expected to run in the near term, thereby lowering GHG emissions within the area. This makes it a potentially higher value location for siting BESS technologies within York Region, when considering reliability and environmental factors. These benefits would be unique to generation sources which are dispatchable, non emitting, and able to be connected to the B88/89H (preferably B89H) circuits.

7.4.3.3 New Northern York transmission supply

In the event that YEC is phased out following its contract expiry in 2035, and equivalent generation is not located in the same general area, it would trigger the need for a new transmission circuit to deliver capacity into Northern York. A typical double-circuit 230 kV line can transfer at least 600 MW of power, though design factors can influence total capacity. Planning this type of infrastructure would require consideration of the initial supply point, the termination, and route between these two points. For a supply point, the anticipated and nearby Kleinburg TS would provide an excellent source of bulk power and given it is expected to come into service in the early 2030s, would likely have more than sufficient capacity for this project. As a termination point, a connection in the same general vicinity as YEC, or at a minimum on the B88/89H circuits would be preferred. This would ensure that new capacity can push against the typically limiting flow away from Kleinburg TS along H82/83V. An ideal connection point would be a new Switching Station (SS), described in the section below, which would link the existing H82/83V circuits with B88/89H, while creating new terminations for the Armitage radial pocket. Having a supply path into this SS would ensure each of the supply points emanating from this station could have a redundant source of supply under multiple configurations and contingencies.

Based on an initial review of the existing corridor between Kleinburg TS and the Holland Marsh area, a new transmission right of way would need to be identified and land acquired to enable this connection. The first section of a proposed corridor could make use of the planned Kleinburg – Kirby transmission link, adjacent to the future Highway 413. Sufficient land is being set aside to enable two double-circuit transmission lines along this route. The first, described in section 7.3.2.2, is expected to be developed in the near term, while the space allocated for the second could be leveraged here. This would allow for a partial new corridor between Kleinburg TS and the approximate intersection of Kirby and Kipling. The remaining ~23km to the Holland Marsh area has an existing transmission line, but there is insufficient land along this corridor to enable a second transmission line. Additionally, there are several points along this corridor where buildings and other geographic features unsuitable for transmission use are immediately adjacent, meaning acquiring new land adjacent to the existing line is either not preferable, or infeasible. As a result, a new route would need to be identified, largely through King township. Given the complexities of siting transmission, namely requiring a linear corridor, with fixed start and end points, and compatible adjacent land uses for the entire route, this could be a costly and disruptive undertaking for the community.

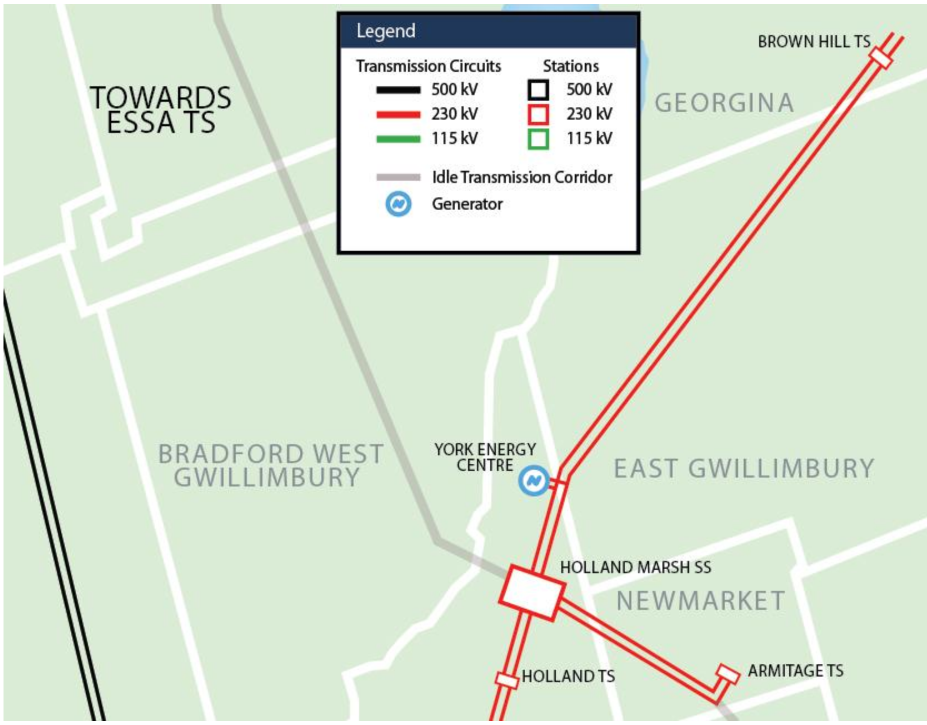
No actions or recommendations are required at this time. However, if YEC is assumed to come out of service in 2035, work should begin no later than 2028 to identify land suitable for a new transmission corridor and initiate development work. Although no site-specific analysis has been undertaken to produce formal cost estimates, typical new corridors of this size, including transmission infrastructure and real estate costs, could be $200-300M.

7.4.3.4 Holland Marsh Switching Station

As described in section 7.5.3.1, the connection of a third Northern York TS along the Claireville to Minden corridor will trigger a security need regardless of whether it is connected to the H82/83V or B88/89V circuits. In addition to the security needs triggered, this section of the grid has been cited by operators as posing significant challenges due to the presence of two sets of inline breakers, and a major system resource facility (YEC). Sectionalizing the existing circuits through a Switching Station (SS) would greatly streamline the operational characteristics, while enabling the connection of Northern York TS #3, and eliminate the most limiting breaker failure contingencies currently affecting the area.

A long-term switching station configuration would be positioned at the existing Holland Marsh junction, to allow for separate circuit termination for the existing H82/83V, modified B88/89H circuits (only the section north of the Armitage junction), and a new, separate radial pocket for Armitage TS. Circuit positions should also be made available for the connection of any future radial circuits required for supply to the Bradford-West Gwillimbury area, and for connection of any new supply transmission line which may be required in the long term, as outlined in Section 7.4.3.3.

Figure 28| Potential future location of Holland Marsh SS



The ultimate configuration of the SS is outside the scope of this study but should be investigated to eliminate the possibility of a common breaker failure triggering simultaneous loss of one H82/83V circuit and one B88/89V circuit. This would eliminate the most limiting breaker failure contingency. If a longer-term connection line into West Gwillimbury is ultimately developed to connect the future Northern York TS #3, an initial preferred switching station arrangement could assume that line terminations are alternated between network lines (B88/89H and H82/83V) and radial lines (Armitage tap, West Gwillimbury Tap).

At this time, the development of a Holland Marsh Switching Station is not required. The current demand forecast suggests that Northern York TS #3, and as a result Holland Marsh SS, would be required in the mid 2030s. However, these assumptions should be revisited during future studies based on actual growth rates, preferred location for future stations, and ultimate connection arrangements. Hydro One has indicated that existing land rights are expected to be sufficient to accommodate this facility when required, with no additional acquisitions required. Switching Stations of this size, including all associated switchgear and breakers, typically cost $200-250 million.

7.4.3.5 Reconductoring H82/83V

As described in section 7.3.2.2, reconductoring of the limiting section of H82/83V between Claireville TS and Vaughan MTS #4 is not a viable option, as the existing corridor is too narrow, and development too close, to allow the work to be completed. However, development north of the proposed Kleinburg-Kirby connection point along H82/83V is significantly less dense. Based on a review undertaken by Hydro One, reconductoring the remaining section between the Kleinburg-Kirby link and Holland Marsh junction is likely feasible.

Following completion of the YEC station service project and the Kleinburg-Kirby link, additional load meeting capability in Northern York is not expected to be required until an additional step-down station is required (notionally Northern York TS #3), and/or following the potential retirement of YEC.

The benefit provided by this reconductoring would depend on the longer-term configuration of the system, including location of demand, supply, and any new infrastructure such as switching facilities. Where thermal limits along the H82/83V circuits are found to be limiting, reconductoring this section could potentially increase LMC by providing improved capacity into a future Holland Marsh SS.

7.5 Opportunities for Non-Wires Alternatives

7.5.1 Large-scale Non-Wires Alternatives

Transmission-connected resources such as large-scale solar, wind, BESS or a combination of these resources were found not adequate to resolve the supply capacity needs covered in Section 6. This is mainly due to 1) connection restrictions in the area due to short circuit limitations at Claireville TS and congestions on the circuits covered in the needs 2) the large magnitude of land required to meet the supply capacity needs of each region sufficiently to defer wires reinforcements.

Installing large transmission-connected resources also do not resolve the station capacity needs in the region, especially in Northern York and the Markham area where downstream feeders cannot viably connect to the system unless new step-down stations are implemented. It is expected that the near-term recommendations described in Section 7.3.2.2, along with the required bulk upgrades described in Section 8.1, will help enable the connection of some resources by resolving the short circuit limitations of Northern York, but congestion constraints will remain in the area, and short circuit issues remain in Southern York.

7.5.2 Demand Side Management

Incremental eDSM can help manage the demand until the next major grid reinforcement or step-down station would be required to cater to the large supply capacity needs. The table below provides a year over year cumulative breakdown of the incremental eDSM potential available per subregion above and beyond that already captured in the IRRP demand forecast.

Table 10| Estimated Incremental eDSM Potential (Cumulative MW) by Subregion

	Northern York	Kleinburg subsystem	Southern Vaughan-Richmond Hill	Markham and Area
2025	18.4	7.7	10.3	9.9
2026	26.3	10.7	13.3	13.4
2027	44.0	17.6	20.3	23.8
2028	35.1	14.1	16.9	18.0
2029	52.5	20.7	23.3	29.1
2030	60.2	23.5	26.8	34.4
2031	70.3	28.1	35.7	45.3
2032	82.5	33.9	47.8	55.9
2033	92.8	38.9	58.9	66.8
2034	103.1	42.5	68.0	78.2
2035	123.9	46.9	76.8	95.5
2036	112.8	44.5	71.7	86.9
2037	141.4	49.6	80.5	100.5
2038	161.0	52.4	84.9	105.7
2039	177.0	55.2	89.1	113.0
2040	190.9	57.6	92.8	123.0
2041	200.0	59.4	96.1	131.5
2042	**211.6**	**61.5**	**99.3**	**137.4**

8 South and Central Bulk Study

IESO is currently also undertaking a bulk 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.

This bulk study is closely linked to the GTA North IRRP and will be key in enabling some of the near-term recommendations discussed above.

Some of the key linkages from the bulk study to this IRRP are as follows:

- Upgrading station (Kleinburg TS) from 230kV to 500kV to support provincial and local needs
- Building an additional circuit from Essa (Barrie) to Kleinburg TS to strengthen electricity flows north/south
- Improving bulk system supply from east GTA towards Parkway TS to help support growth in GTA North
- Determining transmission required to enable decreased bulk system reliance on YEC
- Protecting strategic corridors for future infrastructure to support economic development and community growth

8.1 Bulk Considerations for Enabling the Kleinburg-Kirby Transmission Link

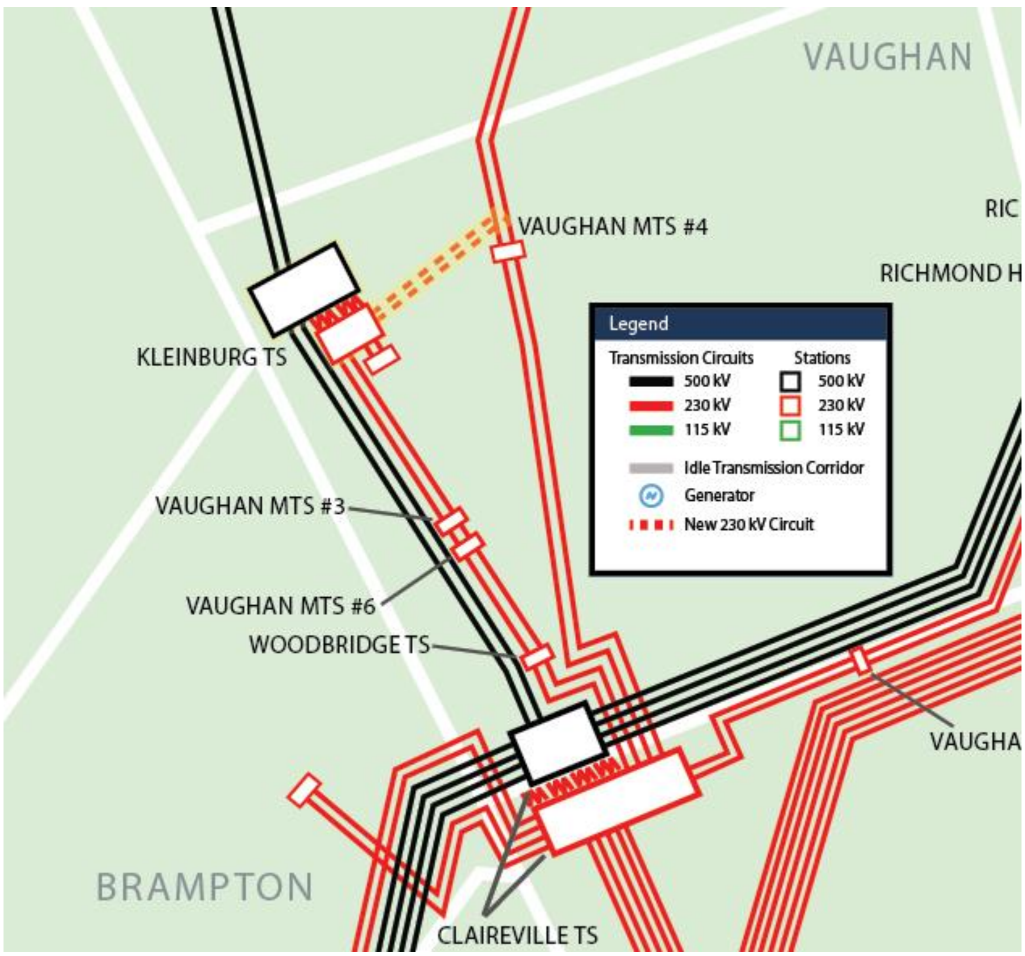
Placing the Kleinburg – Kirby link in service discussed in section 7.3.2.2 will require additional capacity to be available at Kleinburg TS to supply northern York. In the absence of a new supply source, the existing Kleinburg radial tap would become thermally overloaded north of Claireville TS, as the V43/44 circuits would have to carry all existing supply for the local pocket, as well as incremental demand for customers in northern York.

The existing Kleinburg TS, located at the northernmost point of the V43/44 circuits, is currently operated as a step-down station primarily providing distribution supply to customers in Vaughan, Brampton, and Caledon. However, when this site was originally developed, its access to both the regional 230 kV and bulk 500 kV transmission network made it a suitable candidate as a future bulk supply point. Enough land was acquired when developing this station to accommodate additional switching and autotransformer facilities to create a 500kV to 230 kV bulk supply point once required. Based on the current needs for supplying local growth, and broader bulk system benefits identified through a separate bulk planning process, it is recommended that the development of Kleinburg TS as a bulk supply point proceed.

In order to manage higher order contingency scenarios required for the bulk system, three 500 kV to 230 kV autotransformers will initially be required at this site. Space should be set aside to enable the long-term connection of a fourth autotransformer, as a final build out option. Supply to the new autotransformers is to be accomplished through bisecting and re-terminating the existing two 500 kV circuits between Claireville TS and Essa TS. This will require a single 500 kV bus at Kleinburg TS with an initial four 500 kV connection points – two connecting Kleinburg TS to Claireville TS, and two connecting Kleinburg TS to Essa TS.

On the 230 kV yard, space should initially be set aside for six circuit terminations. These would consist of the original two V43/44 circuits, the new double-circuit Kleinburg-Kirby link, and a double-circuit tap to directly supply the existing Kleinburg TS step down station (referred to as Kleinburg DESN hereafter for clarity). Providing a separate connection for the existing Kleinburg DESN would address potential security needs on the Kleinburg radial tap by reducing the amount of capacity supplied by the V43/44 circuits (see section 6.3.3.2). Selecting Kleinburg DESN for direct connection to the 230 kV bus work would minimize connection costs as the station is already located within the facility. In addition to these initial six 230 kV termination points, space should also be set aside for a minimum of four additional positions, to accommodate a potential longer-term need for a new double-circuit 230 kV line into northern York, and a double-circuit 230 kV line spanning westward to supply local demand in northern Brampton and southern Caledon. This latter route would also make use of the planned transmission corridor adjacent to Highway 413. The notional layout of these new facilities is provided below:

Figure 29| Future Kleinburg TS and Kleinburg – Kirby transmission link



This configuration should be considered preliminary at this point and is provided to aid in system evaluation and preliminary site design. Review and further recommendations for the configuration and layout of the Kleinburg TS 500 kV and 230 kV station yards should be carried out by Hydro One as part of the Regional Infrastructure Planning (RIP) process, and final design through the applicable approvals process.

Given that Kleinburg TS is owned and operated by Hydro One today, the development of the Kleinburg TS bulk supply station is not suitable for competitive procurement.

Providing capacity at Kleinburg TS through new local generation, as opposed to creating a new bulk supply point, is not preferred for several reasons.

1. Short circuit levels at Claireville TS are elevated today and will require operational changes at the 230 kV level in order to accommodate additional supply (transmission or generation) at Kleinburg TS.
2. Using a generation source of supply, as opposed to transformers, would require continuous operation and significant load following capability to match local demand. These types of operational requirements are not practical or cost effective for a local system.
3. Transformers are preferred as they provide the benefit to the overall bulk transmission system. Introducing this new supply point in the GTA will provide needed offloading for Claireville TS, enabling growth and the connection of some local resources in the surrounding regions including City of Toronto and Regions of Peel and Halton. while improving long term ability to disperse flows into Essa towards the higher demand centres to the south.

The estimated cost for the development of Kleinburg TS, including all associated switching gear, autotransformers, and reconfiguration of the existing 500 kV system, is approximately $400 M. This station is needed in the near term to accommodate regional growth as well as primarily to serve a bulk system function by managing supply between the existing Claireville TS bulk supply point to the south, and the new supply point to the north, which is better located for accommodating growth throughout northern Halton, Peel, and York regions. The Kleinburg to Kirby link is likewise performing a bulk system function by allowing supply from the new Kleinburg TS to be accessible for regional customers.

Timelines for the implementation of the Kleinburg-Kirby link, and bulk system build out of Kleinburg TS, would ideally align with the proposed in-service date of Northern York TS #1, to ensure infrastructure can be loaded to its full capacity once available. Given typical rates at which new stations are loaded, however, the connection of Northern York TS #1 could be advanced, so long as total loading on the Claireville TS – Brown Hill TS corridor remains under 848 MW, assuming the YEC station service issue has been resolved. This loading level is roughly equivalent to Vaughan MTS #4, Holland TS, and Armitage TS at their full respective LTRs[7], Brown Hill TS loaded at its current summer peak, and the new Northern York TS #1 loaded to 38 MW. Loads of these levels are typical for the first one to two years of a newly in service station. Above this load level, more frequent arming of the existing RAS would be required until the transmission solution has come into service.

8.2 Bringing Bulk Supply from East GTA towards Parkway TS

New generation resources located near Darlington Nuclear Generation stations will become available in early to mid 2030s. The IESO has previously identified a need for a double-circuit going west towards the GTA as an early action to supply the urban centres in the GTA, including the Region of

[7] Inclusive of new Metrolinx loads in Newmarket

York. Parkway TS has been preliminarily selected to be connected to the new double-circuit to reinforce supply into the region while catering for growing demand in the surrounding regions. This option also makes the best of use of available corridor and station real estate in the GTA. It also allows for reconfiguration of existing loads between the key GTA transformer stations, taking short circuit limitations and supply capability into account.

The study will also consider any system reinforcements required to accommodate the new supply downstream of the station in the GTA 230 kV system.

8.3 Additional Essa (Barrie) to Kleinburg TS

In the longer term, larger bulk flows into Essa will also require a third 500 kV line to be built between Essa TS and the proposed Kleinburg TS. This could be triggered from either higher procurement of generation in northern Ontario (such as through expanded hydro development), or the completion of Bruce to Essa transmission upgrades to incorporate expansion at Bruce nuclear GS or large-scale pumped storage between Bruce and Essa zones. This need is based purely on bulk system considerations, and as such timing for the third line will be outside the scope of the GTA North IRRP.

8.4 Decreasing Bulk System Reliance on YEC in the Long Term

As discussed in Section 6.3.2.1, should YEC be phased out following its contract expiry in 2035 or at its eventual retirement at the end of its life cycle, and equivalent generation is not located in the same general area, new transmission infrastructure may be required to cover the capacity shortfall. The bulk study is aimed at studying the impact of the absence of YEC at a wider system level and any potential reinforcements required to adequately supply the region.

8.5 Protecting Strategic Corridors

The IESO is taking early action to identify and protect strategic corridors to enable the long-term infrastructure discussed in the sections above and beyond to enable and support electrification, residential and economic intensification. Three key studies are identified in high-growth areas, including York Region, where land is limited and electricity systems are nearing capacity:

- **Parkway Belt West Corridor**: Exploring future high-voltage transmission lines and transformer stations to support GTA growth and to enable new generation resources.
- **Barrie to Markham Corridor**: Preserving land for a future transmission line to further link Northern and Southern Ontario, to enable growth in Northern Ontario and to supply Southern Ontario with diversified resources.
- **Northwest GTA Corridor**: Refining plans near Highway 413 to support future infrastructure in York, Peel, and Halton.

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, communities, 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 GTA North IRRP.

9.1 Engagement Principles

The IESO's External Relations 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 that 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 30| The IESO's Engagement Principles

9.2 Engagement Approach

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

- Leveraging the GTA North engagement webpage to post updated information, engagement opportunities, meeting materials, input received and IESO responses to feedback;

- Encouraging participants to visit the Powering the GTA website, dedicated to exploring electricity needs and solutions across the GTA;
- Timely and targeted discussions with municipalities and letters prepared for Mayors and Councillors to help inform the engagement approach for this planning cycle;
- Hosted a series of public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions; and
- Communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 9.4).

9.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for the third round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the GTA North Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the GTA North Scoping Assessment Report finalization. A public webinar was held in September 2023 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in October 2023, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, several targeted outreach meetings then began to involve municipalities in the region to ensure growth and development plans have been accurately captured in the Technical Working Group's draft demand forecast and solicit early feedback on the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the GTA North Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected following a comment period after each webinar. The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during public engagements primarily focused on:

- Significant population growth and economic development projects across the region;
- Aligning infrastructure with community infrastructure development;
- Interest in leveraging existing and local generation;
- Alignment of electricity planning with local priorities, such as community and energy plans; and
- Exploring alternative solutions, such as non-wire options, to meet the area's electricity needs.

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.

All interested parties were kept informed throughout this engagement initiative via email to GTA North Region subscribers, municipalities, and Indigenous communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with the significant forecasted growth and development both within specific municipalities and the region more broadly (e.g. significant population and employment growth shared by the City of Richmond Hill, constrained land use shared by the Cities of Richmond Hill and Markham, and capacity constraints shared by Bradford West Gwillimbury). Another key priority was to understand community perspectives on keeping York Energy Centre (YEC) in service past the 2035 contact expiration, which received general support from municipalities and stakeholders highlighting concerns for the remaining supply gap without the facility. These insights have been valuable to the IESO – as they supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's GTA North engagement webpage.

9.4 Involving Municipalities in the Plan

The IESO held meetings with municipalities to seek input on its planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the lower-tier municipalities in York Region to share key developments and to provide an opportunity for municipal feedback on the forecasted regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal and community electricity needs and priorities, establish new relationships, and provide 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 and incorporated in the final IRRP recommendations, including:

- The Town of Stouffville recommended sharing the methodology on how the demand forecast is calculated, including the different variables that are considered.
- The Township of King, the City of Markham and the City of Richmond Hill expressed the need for early and detailed coordination with municipalities to ensure electricity planning aligns with land use policies and congested municipal right-of-ways (ROWs).
- The City of Markham emphasized their preference for utilizing existing station and transmission infrastructure corridors to avoid expanded or new corridors, reducing impact on development and adjacent communities.
- The City of Richmond Hill, and the Town of Whitchurch-Stouffville requested sharing a layout of the power distribution network and detailed mapping of locations for future infrastructure requirements to understand compatibility.
- The Cities of Richmond Hill, Markham and Vaughan detailed significant population and development growth projections in their cities to ensure it is captured in the demand forecast.
- Station capacity concerns were raised in Bradford West Gwillimbury at their Holland TS, and in the City of Vaughan along the Yonge/Steeles corridor.
- Several municipalities highlighted their energy, and sustainability plans and encouraged consideration for non-wire alternatives as solutions in the IRRP in order to align with their net-zero and decarbonization targets.
- King Township and the City of Markham support keeping YEC in service considering the facility already exists and reduces the need for widespread transmission infrastructure and suggest exploring deep retrofits that align the facility with climate goals.

9.5 Engaging with Indigenous Communities

The IESO remains committed to ongoing, effective dialogue with Indigenous communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in the GTA North (York Region) and provide opportunities for input, the IESO invited Indigenous communities that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land use to participate in engagement efforts that included webinars and meeting discussions (virtual or in-person).

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions across Ontario.

10 Summary and Conclusion

The York Region Integrated Regional Resource Plan (IRRP) identifies electricity needs across the region over the 20-year planning horizon from 2024 to 2043 and recommends a coordinated set of actions to address these needs in the near term to enable growth in the region and identifies potential options which may be required in the longer term. The IESO will continue to participate in the Technical Working Group during the next phase of planning, the Regional Infrastructure Plan (RIP), to support implementation and ensure alignment with broader system planning.

In the near term, the Technical Working Group recommends immediate action to address station and supply capacity needs in Northern York, Markham, and Richmond Hill. This includes the development of new step-down transformer stations (Northern York TS #1, Markham MTS #5, and Richmond Hill MTS #3), a new 6-7 km transmission line along the future Highway 413 corridor in Vaughan, reconductoring of existing transmission circuits in Markham, and sectionalization devices to address security needs. To improve reliability, operational measures including reconfiguration of York Energy Centre's power supply, and targeted incremental eDSM are also recommended to manage reliability risks and defer longer-term infrastructure needs.

In the medium- to long- term, the Technical Working Group recommends planning for additional step-down transformer stations (Northern York TS #2 and #3, Markham MTS #6, Vaughan MTS #5), and transmission enhancements to ensure these stations can be reliably supplied. This includes extending the existing Markham transmission line approximately 7 km into northern Markham, to enable the connection and supply of new step-down stations to serve customers in the vicinity of northern Markham, northern Richmond Hill, and Whitchurch-Stouffville. Longer-term needs associated with Northern York TS #3 will likely require additional transmission upgrades in Northern York, including, at a minimum, a new switching station in the vicinity of Holland Marsh junction. The potential retirement of York Energy Centre post-2035 has also been identified as a key driver of future supply needs and would likely trigger the development of a comparably size generator, or a new transmission corridor into Northern York, if this supply source is phased out.

The Technical Working Group will continue to monitor regional developments, including electrification trends, large customer connections, and community energy planning. Opportunities to target incremental eDSM and non-wires alternatives will be evaluated to defer infrastructure needs where feasible. The Working Group will meet regularly to track progress, assess changing conditions, and update the plan as needed. Should significant changes in assumptions arise, the IRRP may be amended or a new planning cycle initiated ahead of the standard five-year schedule.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

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

ieso.ca

@IESO_Tweets
linkedin.com/company/IESO

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