York Region:

Integrated Regional Resource Plan

February 28, 2020

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York Region
Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

The IESO prepared this IRRP on behalf of the York Region Technical Working Group (Working Group), which included the following members:

- Independent Electricity System Operator
- Alectra Utilities Corporation (Alectra)
- Newmarket-Tay Power Distribution Ltd. (NT Power)
- Hydro One Networks Inc. (Hydro One Distribution)
- Hydro One Networks Inc. (Hydro One Transmission)

The Working Group developed a plan that considers the potential for long-term electricity demand growth and varying supply conditions in the York Region, and maintains the flexibility to accommodate changes to key conditions over time.

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List of Acronyms and Alternatives

Acronym/ Alternative	Description
2019 APS	Achievable Potential Study
Alectra	Alectra Utilities Corporation
APO	Annual Planning Outlook
CDM	Conservation and Demand Management
CFF	Conservation First Framework
CHP	Combined Heat and Power
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DG	Distributed Generation
DR	Demand Response
EE	Energy Efficiency
FIT	Feed-in Tariff
GHG	Greenhouse Gas
GTA	Greater Toronto Area
Hydro One Distribution	Hydro One Networks Inc. (Distribution)
Hydro One Transmission or Hydro One	Hydro One Networks Inc. (Transmission)
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LTR	Limited-time Rating
MTS	Municipal Transformer Station
MW	Megawatt
NPV	Net Present Value
NT Power	Newmarket-Tay Power Distribution Ltd.

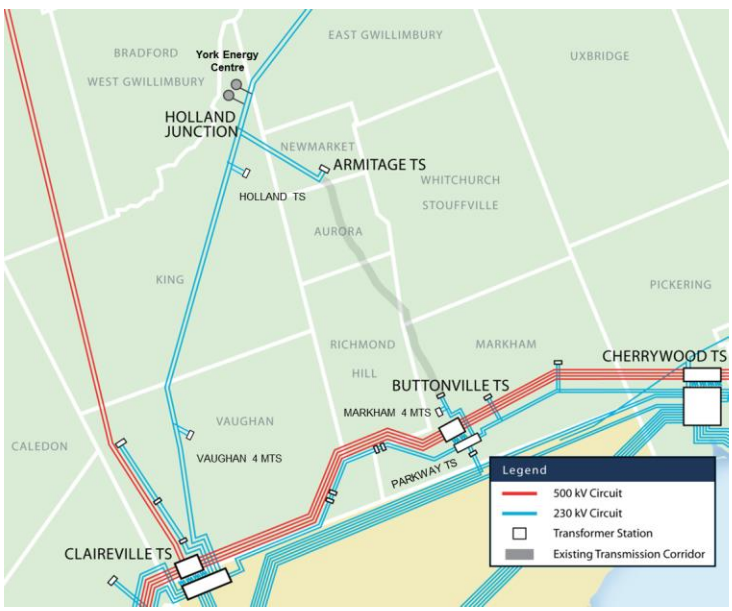
Acronym/ Alternative	Description
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group to the OEB
PV	Photovoltaic (Solar)
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transmission Station or Transformer Station
Working Group	Technical Working Group for York Region IRRP
York Energy Centre	York Energy Centre

1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses electricity needs for the Regional Municipality of York ("York Region" or "GTA North") between 2020 and 2037.[1] 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 1-1, roughly corresponds with the municipal boundaries of York Region. For the purposes of this plan, GTA North and York Regions can be used interchangeably.

Figure 1-1: GTA North (York) Region



[1] The 20-year load forecast covers the period from 2018 to 2037. Consideration for 20+ year demand growth is provided, where relevant.

This IRRP reaffirms the near- to medium-term needs identified in previous electricity system plans for the area, including the 2015 IRRP, 2016 Regional Infrastructure Plan, 2018 Needs Assessment, and 2018 Scoping Assessment. This includes the anticipated need for additional step-down transformation capacity in York Region over the medium term, though need dates have been deferred since the last regional planning cycle.

In the longer term (2030+), the plan reaffirms the need for additional system supply capability. Since the long-term needs are subject to uncertainty related to future electricity demand and technological change, and because of the lead time available, this IRRP does not recommend specific investments to address them at this point. Instead, some viable options are introduced, with a goal of undertaking additional engagement over time to ensure that any final decision is informed by local preferences. At the same time, this strategy maintains flexibility for responding to changes in demand for electricity, and consideration of new solutions, such as non-wires alternatives (including energy efficiency and distributed energy resources).

The plan identifies some near-term actions to monitor demand growth, perform minor transmission system upgrades, continue to pursue information on the feasibility and economics of non-wires alternatives, engage with the community, and develop or maintain viability of long-term supply capacity options. The near-term actions recommended are intended to be completed before the next regional planning cycle, scheduled for 2024 or sooner, depending on demand growth or other factors that could trigger early initiation of the next planning cycle.

This report is organized as follows:

- A summary of the recommended plan for York Region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for regional electricity planning in York Region and the study scope are discussed in Section 4;
- The demand outlook scenarios, and energy efficiency (EE) and distributed energy resource (DER) assumptions, are described in Section 5;
- Electricity needs in York Region are presented in Section 6;
- Options and recommendations for addressing the needs are described in Section 7;
- A summary of engagement activities to date, and moving forward, is provided in Section 8; and
- A conclusion is provided in Section 9.

2. Summary of the Recommended Plan

The near-term recommendations in this IRRP are focused on meeting capacity needs at both the step-down station and regional transmission level, while exploring and preserving options to address the capacity needs expected to emerge in the longer term. Implementation of the recommended actions summarized below is expected to ensure the region's electricity needs are met until at least the late 2020s, and assist in developing recommendations to address needs into the late 2030s.

2.1 Plan for Near-Term Needs (2020-2024)

The recommendations set forth in this plan are summarized below. This IRRP recommends these activities take place within the next five years, either to address a near-term need, or to explore and preserve longer-term options.

Collect Information on Future Non-Wires Alternatives and Opportunities in York Region to inform the next IRRP

Activities are currently underway to inform long-term non-wires potential in York Region, and address some of the operational challenges associated with relying on these technologies to address transmission needs. These activities include an interoperability pilot described further in Section 7.2. The IESO is currently working with government and stakeholders to consider opportunities for EE in Ontario beyond 2020. Consideration of the value of deferring wires infrastructure, in addition to the value of avoided system energy and capacity, should be leveraged and included when determining the feasibility and cost-effectiveness of a program. Many of the municipalities in York Region have developed municipal energy plans that include goals and measures to manage energy use and reduce greenhouse gas (GHG) emissions. Some of these measures have the potential to reduce peak electricity demand, the main driver for capacity needs. In some cases, the positive impact of EE or DERs such as small-scale renewable generation projects may be offset, in the long-term, by a greater reliance on electricity due to end-use fuel switching from fossil sources to electricity.

As part of ongoing engagement with municipalities and stakeholders, the IESO will actively seek new opportunities to target peak electricity demand. In particular, opportunities to align local municipal and stakeholder activities that may help defer the medium-term need for step-down station capacity and long-term need for major system capacity upgrades will be explored and evaluated to determine feasibility and cost-effectiveness. The purpose of this information gathering is to inform the assessment of possible solutions and decisions required in the next IRRP (currently anticipated to be completed in 2025).

Reconfigure York Energy Centre Station Service Supply

The station service supply for York Energy Centre may cause the station to shut off automatically following certain contingencies affecting the transmission system, triggering voltage needs on the regional transmission system. While this risk is currently being addressed by arming automatic load rejection through a Special Protection Scheme (SPS), this measure will no longer be sufficient by approximately 2035, at which point supply security needs will be triggered. Additionally, restoration needs may begin to emerge in the near-term as a result of the temporary generation outage while York Energy Centre returns to service. Given that advancing this work would have immediate benefits for local customer reliability, improve resource availability for the grid, and address the near-term restoration need, this IRRP recommends that the IESO and York Energy Centre's owners and operator proceed with a more detailed investigation to identify and consider options for a preferred long-term station service supply configuration. Any new configuration should allow for continuous York Energy Centre operation following standard design contingencies[2]. Specifically, this includes the simultaneous loss of circuits H82/83V (causing total loss of distribution supply from Holland TS) or the loss of B88H (loss of transmission supply point).

Develop/Preserve Viability of Long-term Capacity Options

As summarized in Section 2.3, a long-term need for additional capacity to supply demand growth is anticipated in York Region. This need could be met through new large-scale dispatchable generation resources, or new transmission.

Two possible transmission options have been identified. One would require the redevelopment of an existing 20-km transmission corridor (Buttonville to Armitage), while the other requires the development of a new transmission right of way (GTA West corridor, Kleinburg to Kirby section), estimated to be around 6 km. A recommendation on the preferred plan to address this capacity needs is not required at this time, but actions should be taken in the near-term to further define, preserve and engage on these options in advance of the requirement for a final decision.

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[2] This measure was recommended in the 2016 System Impact Assessment (SIA) for the Holland Breakers.

The Buttonville to Armitage corridor land is already identified and protected in various official plans. Options for reducing the impact on communities could include evaluating land-use conversions adjacent to the corridor for suitability/compatibility with the potential transmission upgrade (approximately one-third of the corridor is already built-up).

Ongoing work is also underway to identify and preserve space suitable for possible future high voltage transmission adjacent to the proposed GTA West transportation corridor. This new corridor is undergoing an environmental assessment for a new 400 series highway roughly linking Milton to Vaughan. For more information on this initiative, visit the Ministry of Transportation's GTA West Transportation Corridor website. The IESO is currently working with the Ministry of Energy, Northern Development and Mines to assess and preserve options for adjacent land for new transmission capable of meeting long-term capacity needs through the regions of Peel, Halton and York, if and when required. Additional detail on the joint study is available on the IESO's regional planning page for GTA West. Co-location of linear infrastructure is consistent with the Provincial Policy Statement and good planning practice, as it has the potential to lower total land use, reduce the impact on the community and result in cost savings. The section of this corridor with the potential to address long-term York Region capacity needs runs through northern Vaughan, roughly from the Kleinburg TS at the western edge of Vaughan near Bolton, to just north of Vaughan #4 Municipal Transformer Station (MTS) near Kipling Avenue and Kirby Road. This is often referred to as the "Kleinburg to Kirby link." This IRRP recommends that work continue to assess long-term transmission rights adjacent to the GTA West corridor.

2.2 Plan for Medium-Term Needs (2025-2029)

The recommendations described below are intended to address medium-term needs (five to 10 years out). Although actions are not required immediately, some may be initiated before the next round of regional planning is undertaken. Anticipated need dates, and triggering events, are described as required.

Reconductor Circuit P45/46 from Parkway to Markham #4 MTS

The Working Group recommends that Hydro One proceed with reconductoring a limiting circuit segment to a higher ampacity. This upgrade will enable an additional 180 MW to be served in the Markham area without exceeding thermal limits of the regional transmission system. The upgrade is recommended to be complete by the time the new Markham #5 MTS comes into service (currently forecast for 2025), to ensure full station loading is available. Based on a high-level assessment of costs, this upgrade is expected to cost approximately $2 million.

Address the Potential for High Voltages on M80/81B

A potential voltage rise need may emerge on the M80/81B circuits and connected step-down stations beginning in 2025. The need is triggered under high-load conditions following the loss of B88/89H, and is worsened by the use of capacitor banks at Lindsay TS and Beaverton TS (required to prevent voltage drop under different contingencies). This need can be addressed in a number of ways, including operational measures. This would not require new infrastructure. It is recommended that Hydro One TX investigate this need, identify a preferred solution through the RIP process, and implement that solution no later than 2025.

New Step-down Stations to Supply Growing Demand in Markham, Northern York and Vaughan

Step-down stations are points along the transmission network where electricity is converted, through step-down transformers, to lower voltages for distribution customers. Based on the anticipated growth forecast, up to three new step-down stations will be required in York Region in the medium term. The first anticipated need is for a Markham #5 MTS in 2025, followed by a Northern York TS (notionally 2027) and Vaughan #5 MTS (notionally 2030). The need dates for all three step-down stations could be deferred by NWAs that target peak demand electricity use, with the longer-term need dates more candidates for deferral. Because of the meshed nature of Alectra's distribution grid in southern York, any non-wires initiative targeting peak demand within the municipalities of Vaughan, Richmond Hill or Markham could help defer the need dates for Markham #5 MTS as well as Vaughan #5 MTS. In order to defer a new Northern York TS, measures targeting the higher-growth northern municipalities of Newmarket, East Gwillimbury and Aurora would likely be the most effective.

Three technically feasible sites for the first station (Markham #5 MTS) were assessed in this IRRP based on overall project cost (transmission and distribution); both the central and northern candidate sites were found to be similar in terms of cost. For this reason, the Working Group recommends that Alectra select a preferred site after engagement with the community, as local preferences may depend on weighting various criteria such as land use or another potential impacts.

Although other locations are possible, at this time it is assumed that the future Northern York TS will be located in the vicinity of East Gwillimbury based on its high-growth rate and the lack of nearby step-down stations[3]. This IRRP recommends that Hydro One undertake a review of suitable locations to accommodate a potential in-service date as early as 2027. A preferred location for Vaughan #5 MTS has already been identified, by Alectra, and land set aside at the site of the existing Vaughan #4 MTS. This location is well suited to serving growth in northern Vaughan, and could be required as early as 2030.

Sufficient capacity exists along the existing Claireville to Minden 230 kV circuits to accommodate one additional station over the forecast period. However, two new stations, such as Northern York TS and Vaughan #5 MTS, are anticipated to be required in the medium to long term. As the incremental demand of these two stations is expected to trigger long-term capacity needs on the Claireville to Minden circuits by the early to mid-2030s (see Section 2.3, below), a preferred option to address the overloading of these circuits must be identified before committing to the connection of the second station.

2.3 Plan for Long-Term Needs (2030+)

No actions are required at this time to address long-term needs. However, given the potential cost, impact, and community interest in these potential long-term solutions, engagement should continue between planning cycles. The information below is provided to help inform discussions and highlight key issues when comparing feasible solutions.

Increase Supply Meeting Capability for Claireville to Minden Circuits

Continued load growth in York Region is expected to trigger the need for new capacity on the Claireville to Minden circuits, with a current anticipated need date of 2033[4]. While this need has the potential to be deferred through NWAs, actions are required in the near term to ensure long-term wires solutions remain viable.

Both new transmission and large-scale, dispatchable resources have the potential to address this long-term need. A recommendation on the final preferred option to address these capacity needs is not required at this time, and is not expected to be needed until at least 2025. The actual need date will depend on the amount of peak demand being supplied along the limiting circuit

[3] This is subject to change based on land availability and further assessments by Hydro One TX

[4] Based on the demand forecast developed for this IRRP

section between Claireville TS and Vaughan #4 MTS. Based on the load forecast, this will likely occur shortly after Vaughan #5 MTS comes into service. As a result, work to identify a preferred alternative, including engagement with affected communities, should continue to ensure that a preferred option can be identified before committing to the connection of Vaughan #5 MTS. These discussions should reflect new information as soon as it becomes available, including the annual review of actual load growth (net impact of new growth minus efficiency gains and the impact of NWAs), the status of and recommendations from the neighbouring GTA West IRRP, long-term anticipated provincial capacity needs, and the status of initiatives to preserve long-term transmission corridor options.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet an area's electricity needs at a regional level is completed through the regional planning process, which assesses regional needs over the near, medium, and long term, and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing transmission electricity infrastructure, local supply resources, forecast growth and area reliability; evaluates options for addressing needs; and recommends actions to be undertaken.

The current regional planning process was formalized by the OEB in 2013, and is conducted for each of the province's 21 electricity planning regions by the IESO, transmitters and local distribution companies (LDCs) on a five-year cycle.

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;
2) A scoping assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3) An IRRP, led by the IESO, which identifies recommendations to meet needs requiring coordinated planning; and/or
4) An RIP led by the transmitter, which provides further details on recommended wires solutions.

More information on the regional planning process and the IESO's approach to regional planning can be found in Appendix A: Overview of the Regional Planning Process.

3.2 York Region Technical Working Group and IRRP Development

In accordance the OEB's regional planning process, Hydro One kicked off the current cycle of the regional planning process with the Needs Assessment for GTA North (York Region) in 2018. The Needs Assessment identified needs requiring further assessment and coordinated regional planning, resulting in the initiation of the Scoping Assessment process.

Based on the findings of the Needs Assessment, the Scoping Assessment process concluded that an IRRP was the appropriate planning approach for the GTA North (York Region).

In August 2018, a Technical Working Group (Working Group) began gathering data, conducting assessments to define near to long term needs, identify possible solution options, and recommend actions to address York Region's electricity system needs.

Specifically, the IRRP was initiated to:

- Explore innovative wires and/or non-wires solutions and determine the extent to which these could be leveraged to address or defer regional transmission needs in York Region;
- Determine whether development work or commitments to infrastructure investments (wires or non-wires) are needed in this planning cycle;
- Assess potential risks over the longer term and identify near-term actions to manage or mitigate these risks, where applicable.

4. Background and Study Scope

The GTA North Region (York Region), as shown in Figure 4-1, comprises the municipalities in York Region, including Vaughan, Richmond Hill, Markham, Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville, Georgina, and Chippewas of Georgina Island. Its electrical infrastructure also serves parts of the City of Toronto, Brampton, and Mississauga.

Figure 4-1: Geographical Boundaries of GTA North (York Region)

York Region is one of the fastest-growing regions in Ontario. Provincial policies, including the *Places to Grow Act, 2005* and the *Greenbelt Act*, 2005 have played a key role in facilitating and driving local development. While a large portion of the land in this region is part of the Greenbelt, a permanently protected area of green space, farmland, forests, wetlands and watersheds, the *Places to Grow Act, 2005* promoted rapid intensification and development in designated urban areas surrounding the Greenbelt. Extensive urbanization in these areas over the past decade has resulted in continued growth in the demand for electricity. In 2017, York Region had an electricity summer peak demand of over 2,000 MW. Following the province's updated *Growth Plan for the Greater Golden Horseshoe, 2019*, significant population growth and urban intensification are expected to continue in the region in the coming decades.

At the same time, many communities in York Region, including the City of Markham, City of Vaughan, Town of Newmarket, Region of York and Chippewas of Georgina Island First Nations, are actively engaged in local energy planning activities and are exploring opportunities to better manage their energy use using community-based energy solutions, such as energy storage, combined heat and power (CHP) and renewable energy resources.

4.1 Recent History of Electricity System Planning in York Region

Regional electricity planning in York Region has been underway for a number of years. Below is a summary of key products and planning decisions which have shaped York Region's current electricity system.

2005 Northern York Region Electricity Planning Study

In 2005, in response to a letter of direction from the OEB, the IESO (then the Ontario Power Authority or OPA) led the development of an integrated electricity planning study for Northern York Region. At the time, the electricity supply infrastructure to this area had reached its limits, resulting in an urgent need to address risks to customer reliability resulting from strong electricity demand growth. The planning study considered transmission, distribution, generation, and conservation options, and was developed with input from local stakeholders.

The resulting 2005 Northern York Region plan recommended a number of actions, most notably the addition of a simple cycle gas-fired peaking generation station, which was later procured, in the form of the York Energy Centre. York Energy Centre came into service in 2012. This solution enabled the communities in Northern York Region to continue to grow, while maximizing use of the existing transmission in the area.

2016 Regional Plan

The first cycle of the regional planning process for York Region was completed in 2016, with the focus on ensuring adequate supply to support near-term growth in the Vaughan area and minimizing the impact of supply interruptions under outage conditions. Through this newly formalized regional planning process, a number of projects were recommended to support near-term growth and further maximize the use of the existing system, including a new transformer station in Vaughan, new switching equipment at Holland TS, and on the parkway belt/Highway 407 transmission corridor. All of these projects have since come into service. Even with the implementation of these near-term projects and the ongoing conservation efforts identified and underway at the time, electricity demand growth was forecast to exceed system capability in the Markham-Richmond Hill area in the early 2020s and Northern York-Vaughan in the mid to late 2020s.

Work since last regional planning cycle

Since the completion of the first cycle of the regional planning process in GTA North (York Region), the Working Group has taken steps to better understand the extent to which non-wires solutions can be used to help manage growth in electricity demand in the medium to longer term. Specifically, in 2016, Alectra and the IESO conducted a study to examine the feasibility of implementing residential solar-storage technology in Markham, Richmond Hill and Vaughan. Information on the POWER.HOUSE initiative and its conclusions are available in the final study. Given the timing and magnitude of electricity demand growth in the Markham-Richmond Hill area, the study confirmed that it was not feasible to solely rely on residential solar-storage technology to defer the near-term supply need in this area. The IESO, on behalf of the Technical Working Group, confirmed the need for a new transformer station and associated lines in the Markham-Richmond Hill area by 2023, and provided a letter to Hydro One and Alectra to initiate the development work for this project. The need date for this station has since been deferred to 2025 (as described in this IRRP).

Over the last couple of years, the IESO and the local utilities have continued to engage with municipalities and Indigenous communities in York Region to confirm the projected growth, inform them of the state of electricity system needs and associated distribution and/or transmission in the area.

4.2 Study Scope

This IRRP, prepared by the IESO on behalf of the Technical Working Group, recommends options to meet the electricity needs of York region over the 2020-2037 timeline. Guided by the principle of maintaining an adequate level of reliability performance as per the *Ontario Resource and Transmission Assessment Criteria* (ORTAC), this IRRP reviews needs identified and discussed as part of the Scoping Assessment, with the focus on:

- Providing an adequate, reliable supply to support community growth
- Minimizing the impact of supply interruptions
- Coordinating and aligning end-of-life asset replacements with evolving needs

Given that the York Region 230 kV networks also serve as major pathways for the flow of power between northern and southern Ontario and across the GTA, the IRRP also assesses the York Region 230 kV networks under various bulk system conditions. However, a detailed assessment of the bulk electricity system is typically addressed through separate planning processes and is beyond the scope of this IRRP.

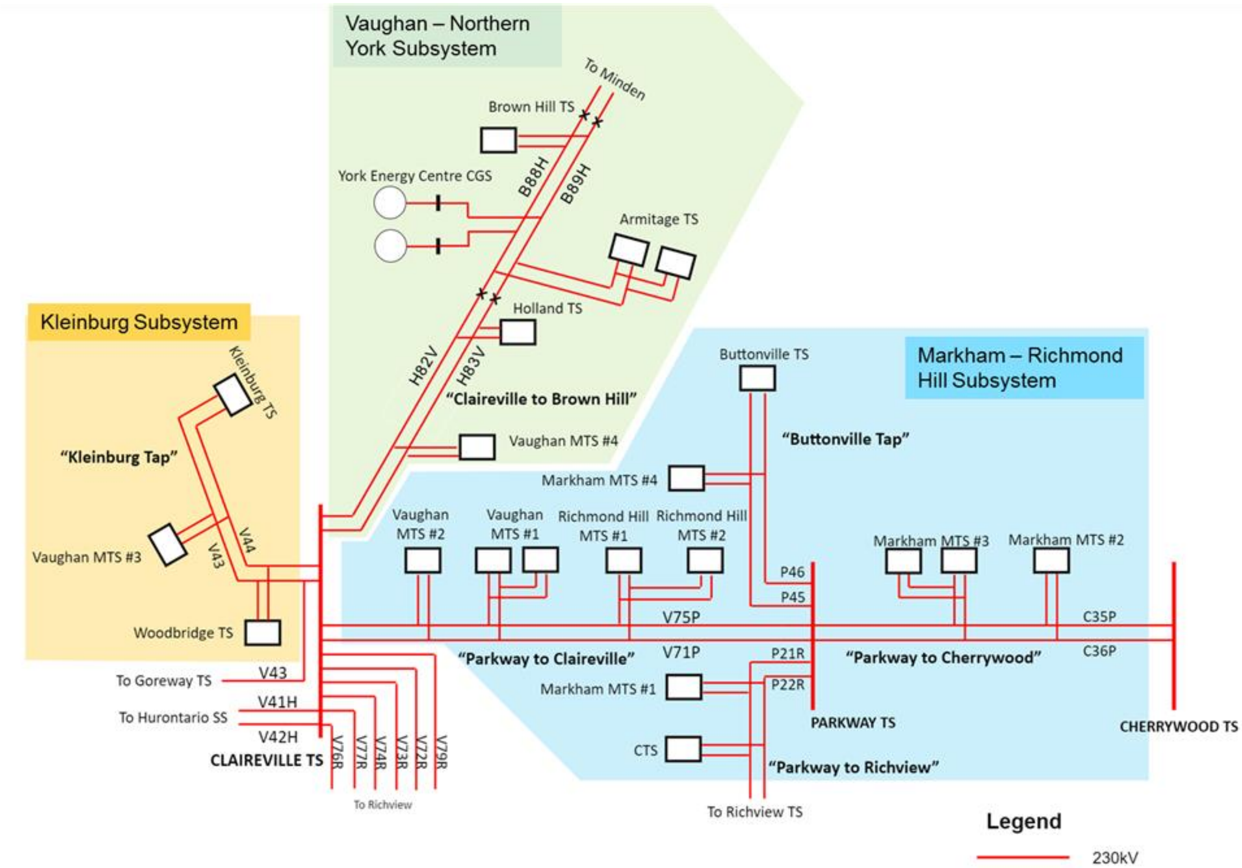
York Region 230 kV networks

Today, as shown in Figure 4-2, power is delivered from the rest of the province into this region through a 230 kV transmission network that also serves as a pathway for power to flow between northern and southern Ontario and across the GTA.

Through these 230 kV subsystems, power is delivered to various communities and customers through 20 customer and utility owned step-down transformer stations through lower voltage distribution networks. The distribution system is managed and operated by five LDCs: Alectra, NT Power, Toronto Hydro Electric System Ltd., Veridian Connections Inc., and Hydro One Distribution. All LDCs are directly connected to the transmission system, with the exception of Veridian which is embedded within Hydro One's system.

In addition to the transmission network, electricity supply to the area is also provided by York Energy Centre, a 393 MW simple cycle gas-fired generation facility that came into service in 2012.

Figure 4-2: Single Line Diagram of GTA North (York Region)



For the purpose of regional planning, this 230 kV network can be broken down into three 230 kV subsystems, as shown in Figure 4-2:

- **Kleinburg 230 kV Subsystem (V44/43)** – This radial subsystem consists of three step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon and, to a lesser degree, Brampton, Mississauga and Toronto. Power is delivered into this subsystem from Claireville TS via the 230 kV transmission circuits V44 and V43.

- **Vaughan-Northern York 230 kV Subsystem (B82/83H, H82/83V)** – 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 Chippewas of Georgina Island). York Energy Centre is connected to these 230 kV circuits. This subsystem also serves as a pathway for power flows between northern and southern Ontario.

- **Markham-Richmond Hill 230 kV Subsystem (P45/46, C35/36P, V75/71P, P21/22R) –** This subsystem consists of 12 step-down transformer stations located in urban communities in the Markham, Richmond Hill and Vaughan areas. This subsystem, which also serves as a major pathway for power to flow east-west across the GTA, is further broken down into four sub components:

  (1) Buttonville Tap - P45/46
  (2) Parkway to Cherrywood - C35/36P
  (3) Parkway to Claireville - V71/75P
  (4) Parkway to Richview - P21/22R

Completing the York Region IRRP involved:

- Preparing a long-term electricity peak demand forecast;
- Examining the load-meeting capability and reliability of the transmission system supplying the region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities (such as reactive power devices);
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible EE, generation, transmission and/or distribution, and other approaches such as non-wires alternatives (NWAs);
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Peak Demand Forecast

A fundamental consideration in any electricity supply study is how much electricity will be required in the region over the study period. This section outlines the electricity demand forecast within York Region over the 20-year study period, highlighting the assumptions made for peak demand load forecasts, and the expected contributions of EE and DERs to reducing or offsetting peak demand. When combined, these factors produce the net demand forecast used to assess the electricity needs of the area over the planning horizon.

For the purpose of evaluating the adequacy of the electricity system, regional planning is concerned with the coincident peak demand for a given area, or the demand observed at each station for the time of year when overall demand in the study area is expected to be at its highest. This represents the moment when assets are at their most stressed, and resources generally the most constrained. This is different from non-coincident peak, which is the sum of the individual peaks at each station, regardless of whether these peaks occur at different times. Within York Region, the peak loading hour for each year typically occurs in late afternoon during summer (4 p.m. to 6 p.m.), usually on the hottest weekday, or after consecutive hot days. Peak load is weather sensitive, and generally driven by air conditioning loads of residential and commercial customers. This typically occurs on the same day as the overall provincial peak, but may occur at a different hour in the day.

5.1 Methodology for Preparing the Forecast

The peak demand forecast used to identify needs in this IRRP was developed in the following stages:

1. The IESO weather-corrected the most recent year's demand data to create a forecast "start" point based on expected peak demand under median (or "most likely") weather conditions. This is done to ensure that LDC forecasts begin at a common data point. The demand forecast was normalized to a 2017 start point, broken down by transformer station, LDC, and step-down voltage (where applicable).
2. Each LDC developed its own demand forecast by transformer station starting from the start point data provided by the IESO. Since LDCs have the closest relationship to customers, connection applicants, and the municipalities, they tend to have a better understanding of future load growth and local drivers than the IESO. The IESO typically carries out load forecasts at the provincial level.
3. The IESO aggregated the LDC forecasts by transformer station, and subtracted the estimated impact of codes and standards, historic EE and committed future EE

programs from the future demand. These estimates were based on provincial policy and informed by the customer mix served by each station.
4. Finally, station-level forecasts were adjusted to account for the predicted impact of extreme weather conditions.

The result was a station-by-station outlook of annual peak demand from 2018 through to 2037. Actual observed peak demand in 2018 was used to validate the forecast, and assessments were performed on forecast years beginning in 2020.

More details on these assumptions, including station-level forecasts, may be found in Appendix B: Peak Demand Forecast.

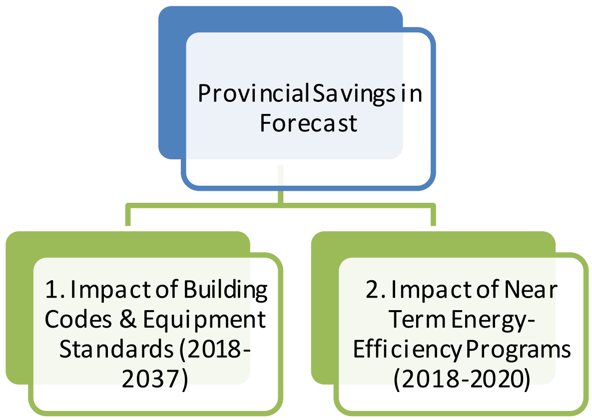
5.2 Existing or Committed Energy-Efficiency Assumptions in Forecast

Energy efficiency (EE) is achieved through a mix of program-related activities, and mandated efficiencies from building codes and equipment standards. It plays a key role in maximizing the use of existing assets and maintaining reliable supply by offsetting a portion of a region's growth in electricity demand, and helping to ensure it does not exceed equipment capability. The estimated impact of existing or committed EE programs and codes and standards for York Region have been applied to the gross peak-demand forecast for median weather, along with DERs (described in Section 5.3), to determine the net peak demand for the region.

Future EE savings for York Region have been applied to the gross peak-demand forecast to take into account both policy-driven and funded EE through the provincial Interim Framework (estimated peak demand impacts due to program delivery to the end of 2020), as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast. As policies related to future provincial EE activities change, the forecast assumptions will be updated accordingly.

To estimate the peak-demand impact of existing and committed EE savings in the region, the forecast for provincial savings were divided into two main categories, as shown in Figure 5-1.

Figure 5-1: Existing or Committed Energy-Efficiency Savings Categories



1. *Savings due to building codes & equipment standards*
2. *Savings due to the delivery of energy-efficiency programs*

For York Region, the IESO worked with LDCs to establish a methodology to assess the estimated savings for each category, which were further subdivided by customer sector: residential, commercial, and industrial. This approach reflects the differing energy consumption characteristics and efficiency measures.

LDCs provided both their gross-demand forecast and a breakdown of electrical demand by sector for each TS. Once sectoral gross-demand at each TS was estimated, peak-demand savings were assessed for each energy-efficiency category: codes and standards, and EE programs. Due to the unique characteristics and available data associated with each group, estimated savings were determined separately. The final estimated EE peak-demand reduction, 146 MW by 2037, was applied to the gross demand to create the planning forecast.

Table 5-1Table 5.1 shows the total peak demand savings attributable to existing and committed EE and codes and standards for York Region, for selected years within the planning horizon.

Table 5-1: Forecast Peak Demand Savings from existing and committed Energy Efficiency

Year	2020	2025	2030	2037
Estimated savings (MW)	66	98	111	144

Source: IESO

A more detailed methodology on the outlook for EE, including assumptions and a breakdown by station and year, is provided in 1.1.1Appendix B: .

5.3 Distributed Energy Resources Assumptions

In addition to EE, DERs in York Region are expected to continue to offset peak demand. Previous procurements, including the Feed-in Tariff (FIT) Program, have led to an increase in the amount of renewable DERs in York. Other competitive generation procurements have also resulted in additional DER projects, such as combined heat and power. As of November 2019, more than 1,300 DERs in York Region were under contract with the IESO. The vast majority of these are small-scale (under 10 kW) solar photovoltaic (PV) systems.

Further to these, the IESO conducted competitive procurement pilots to acquire energy storage resources and support efforts to better understand barriers related to the integration of energy storage into Ontario's wholesale electricity markets. One of these, in the Newmarket area, is a 4 MW (16 MWh) battery project intended primarily to support capacity needs on the distribution system. However, with the close alignment between local and system peak, the project is likely to provide some transmission system capacity benefit as well.

Table 5-2 shows the predicted impact of existing DERs within York Region. Capacity contribution assumptions were taken from the most recent IESO Methodology to Perform the Reliability Outlook.[5]

[5] See the December 19, 2019 version of Methodology to Perform the Reliability Outlook, with associated Reliability Outlook – Tables.

Table 5-2: Active DER Contracts in York Region as of November 2019

	# of Contracts	Total Contract Capacity (MW)	Effective Capacity (MW)
Markham and Richmond Hill stations *(Markham MTS #1-4, Richmond Hill MTS #1-2, Buttonville TS)*	306	25.94	13.77
Vaughan and Kleinburg stations *(Vaughan MTS #1-4, Kleinburg TS)*	344	20.69	5.81
Northern York stations *(Armitage TS, Holland TS, Brown Hill TS)*	692	50.92	7.93
Total	**1,342**	**97.55**	**27.51**

The impact of existing DERs is already accounted for in the load forecast, as their effect on electrical demand shaped the historical data used to create the forecast start point. As a result, no additional modelling or analysis was required. The one exception was three 10 MW solar PV facilities connected at Brown Hill TS, as large variations in output over summer peak hours made it challenging to observe “typical” summer demand behaviour. For this station, the hourly output from these generation facilities was added back to the hourly meter readings to determine what load would have been in the absence of 30 MW of solar PV. This allowed for a more realistic customer demand start point to use in the forecast. The expected future impact of this PV facility was then subtracted from the gross forecast based on the capacity contribution of solar PV resources during peak periods in summer months.

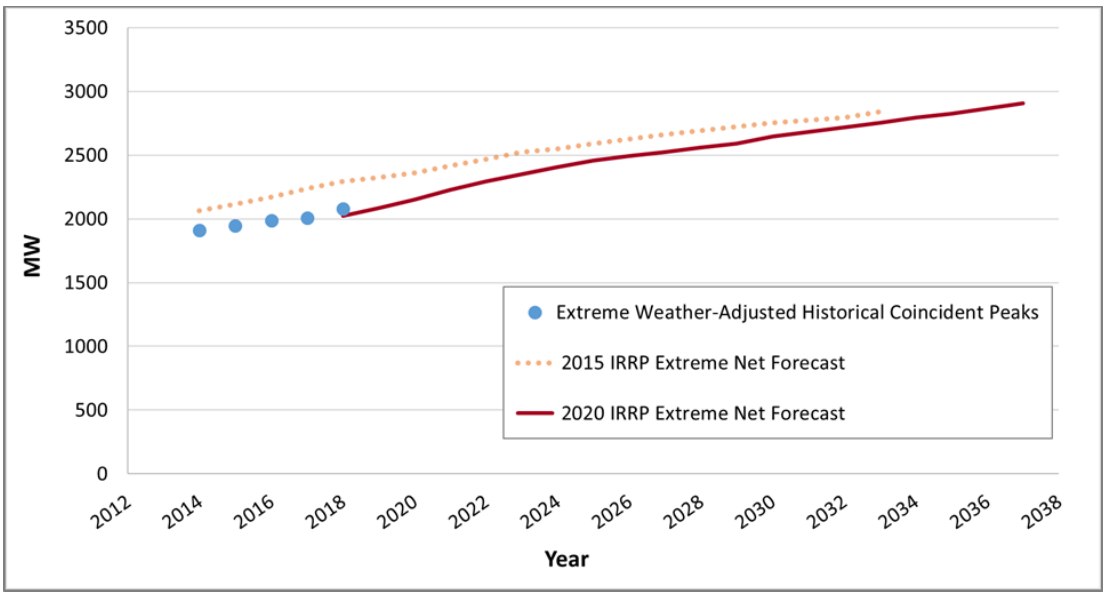
Given the difficulty of predicting where future DERs may be located, and uncertainty around future DER uptake, no further assumptions have been made regarding future DER growth. Instead of assuming DER growth implicitly as a load modifier in the demand outlook, the potential of future DERs is considered as a possible solution option. This is discussed further in Section 7.2.

5.4 Final Peak Demand Forecast

The final peak demand forecast was used to carry out system studies, and was the primary input for identifying potential needs. It was prepared by taking the gross median weather forecasts prepared by LDCs, and accounting for the impacts of EE and large DERs, as described in the preceding sections. The methodologies used by the LDCs to prepare their gross forecasts are available in Appendix B: Peak Demand Forecast. The forecast was further adjusted to account for the expected impact of extreme weather conditions, and typical station loading and operational practices (e.g., load transfers).

Figure 5-2 shows the final peak demand forecast, aggregated for the entire study area. For comparison, the figure also shows the most recent five years of historical peaks, adjusted for extreme weather, and the corresponding forecast used in the 2015 IRRP. Note that the forecast was finalized before 2018 peak demand data was available. As a result, the 2018 peak does not influence the start point of the forecast; instead, it is shown to validate the initial year of the forecast.

Figure 5-2: Peak Demand Forecast



The electricity demand growth rate fluctuates between 1.1% and 3.5% annually, averaging 1.9% over the 20-year study period. The growth is consistently higher in the near and medium term periods, with an average annual growth of 2.5% to 2027. The average growth rate is 1.4% from 2028 to 2037.

The continued high growth shown in this forecast is consistent with the A Place to Grow: Growth Plan for the Greater Golden Horseshoe (2017) and the York Region Official Plan (2019), which project an increase in population from 1,109,909[6] to 1,790,000, and employment growth from 595,200[7] to 900,000 jobs in York Region between 2016 and 2041. This represents an average

[6] York Region, 2016 Census
[7] York Region Employment and Industry Report 2016

annual population and employment increase of 2.45% and 2.05% per year, respectively. Although population and employment growth cannot be directly correlated to growth in power demand, more people and more jobs will result in upward pressure in electricity demand. Other factors, such EE or DERs, the density of development, and end-use electrification can also impact the demand for electricity.

The York Region Official Plan focuses on intensification, which is expected to drive new development. Consistent with the load growth seen in the final forecast, the municipalities of Newmarket, Vaughan, Richmond Hill and Markham, listed as the region's four centres, are expected to have the most intensification.

Between 2018 and 2037, stations located within the Vaughan sub-region (Vaughan 1-4 MTS, Kleinburg TS) show the largest average growth rate at 2.4% per annum. Within the same time period, the Markham sub-region (Markham 1-4 MTS, Richmond Hill TS, Buttonville TS) is expected to have a slightly lower average growth rate, at 2.0% per annum. Finally, the smallest average growth rate, at 1.2% per annum, is seen in the Northern York sub-region (Armitage TS, Brown Hill TS, Holland TS).

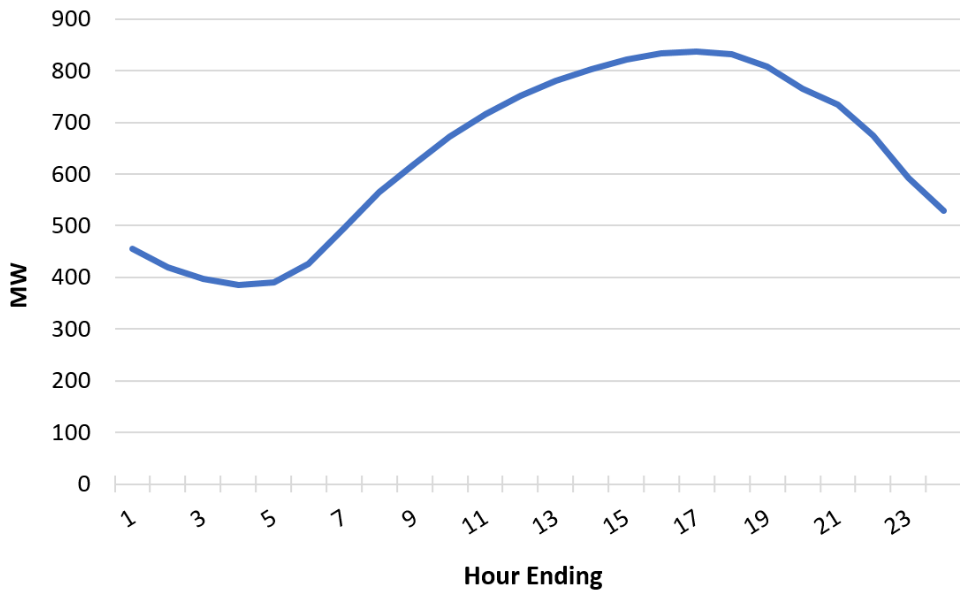
5.5 Load Duration Forecast (Load Profile)

While the final peak demand forecast is the primary input used to identify system needs, including timing and magnitude, it is only concerned with the single point of highest demand in the year (i.e., peak hour). This does not provide information related to the frequency of needs, the time of day, or the duration in which the electricity system assets are stressed during peak demand events. This information is especially important for evaluating the potential for NWAs, which may perform better at certain times of day, or for only fixed amounts of time, to defer needs.

For this type of option screening, an hourly forecast, known as a load duration forecast, was developed to predict the suitability of certain solution types to meet an area's demand, and to aid with cost estimations. Using historical hourly duration information, a sample 8,760-hour profile was created and scaled such that the peak hour would align with the peak demand forecast in a given year. Two separate profiles were created for each year of the peak forecast -- one to represent the combined loadings of all stations served by the Claireville to Brown Hill circuits (B88/89H and H82/83V); and the second to represent the sum of all stations serving load in Markham (Markham MTS #1-4). These area profiles represent the needs expected to trigger wires solutions over the 20-year study period. A sample of a typical peak-day profile for the Claireville to Brown Hill circuits is shown in Figure 5.3.

Figure 5-3

Figure 5-3: Sample Duration Profile for Claireville to Brown Hill Stations (July 15, 2032)



Additional details on how forecast profiles were created are available in Appendix B: Peak Demand Forecast.

Due to the higher level of uncertainty associated with predicting hour-by-hour demand for electricity, the results should be considered as qualitative (providing more information on needs already identified using the peak demand forecast) rather than quantitative (identifying needs). Profiles were also used to predict the suitability of certain NWA solutions to address specific needs, and to estimate feasibility and cost.

6. Electricity System Needs

Based on the demand forecast, system assumptions and application of provincial planning criteria, the Technical Working Group identified electricity needs in the near, medium, and long term. This section describes these needs, which are grouped into three categories: step-down station capacity, system capacity, and supply security and restoration. Each section begins with a brief description of the type of need, including how needs are identified, and details on each need identified through the technical assessments.

6.1 Step-Down Station Capacity Needs

Step-down transformer stations convert high-voltage electricity from the transmission system into lower-voltage electricity for delivery through the distribution system to end-use customers. Each station is capable of converting a maximum amount of power at a time, which is referred to as its Limited-time Rating (LTR). Loading a station beyond this amount is not permissible except in emergency conditions, as it lowers the life expectancy of facility equipment and can impact reliability for customers.

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 exceed its LTR to a nearby station with available capacity. Feasible load transfers are already assumed in the demand forecast based on conversations with LDCs regarding the transfer capabilities and typical loading practices. Load transfers assumed include the following.

- **Holland-Armitage TS transfers**. Once Armitage TS reaches its full LTR, incremental load is assumed to be supplied from Holland TS.
- **Vaughan-Richmond Hill-Markham MTS transfers**. Due to the meshed distribution network design for the southern municipalities of Vaughan, Richmond Hill, and Markham, most Alectra load can be shifted between stations in the area. This is represented in the load forecast by flat (maximum LTR) demand at all but the newest step-down station in the area. Since new stations are planned to alternate between a Vaughan and Markham location, this also means that demand in one municipality appears "flat" while the other grows, and vice versa.

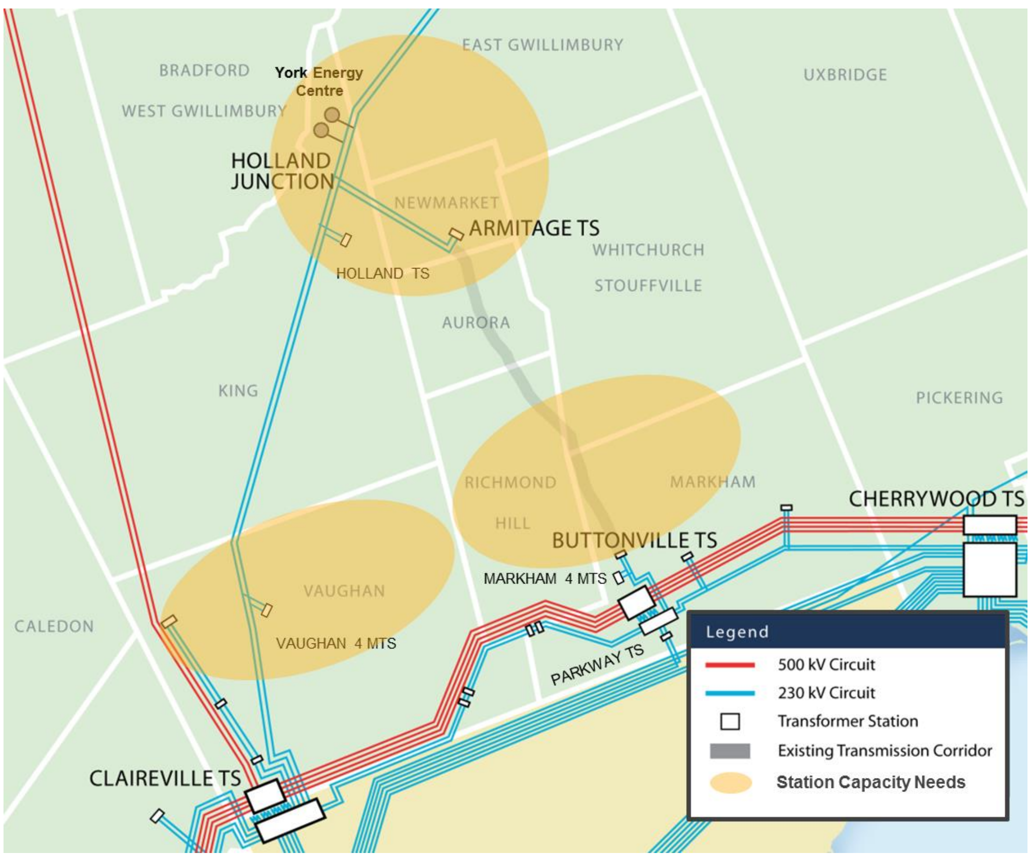
When a step-down station's capacity is reached, and feasible transfers are accounted for, options for addressing the need include reducing peak demand in the supply area (e.g., through EE or DERs), or building new step-down transformer capacity to serve incremental growth.

Typically, where there is sustained new urban growth and development in an area, measures to reduce peak demand growth are not able to defer the need for a new station indefinitely. The cost of these measures are compared to the value of deferring construction of a new station. These options are described in greater detail in Sections 7.1 and 7.2.

In order to build a new step-down station, a suitable location must be identified. Stations must be connected to a part of the transmission system with enough incremental capacity available to reliably supply the station load (See System Capacity Needs, Section 6.2). 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.

Figure 6-1 shows the general areas of anticipated step-down station needs based on the load forecast, system assumptions, and growth patterns through the region.

Figure 6-1: Areas of Anticipated Step-down Station Capacity Need



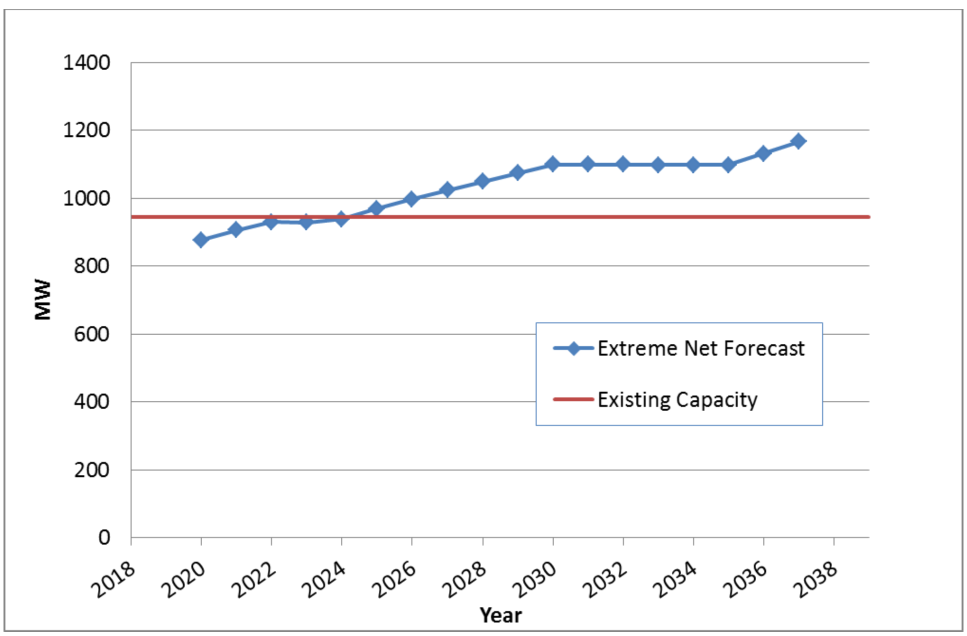
Additional information on station capacity needs for the identified areas is provided in the sections below.

6.1.1 Markham

The population of Markham is currently more than 340,000, and is projected to increase to over 420,000 by the year 2031.[8] Like the other southern York municipalities of Vaughan and Richmond Hill, most of the built up areas are in the south and central parts of the city, while the new growth over the coming decades is mostly expected to advance northward.[9] This has implications for locating future step-down stations, as transmission supply is currently only available along the Parkway transmission corridor in the south (adjacent to Highway 407), and along the Buttonville tap, which extends north roughly halfway into Markham. For the purpose of transmission planning, growth in Richmond Hill is considered also, as this area relies on the same supply infrastructure. Richmond Hill and Markham both have similar challenges in supplying northern growth increasingly further removed from the existing grid. Richmond Hill is roughly a third smaller than Markham with a current population of around 220,000, which is projected to increase to just over 240,000 by 2031.

The combined load forecasts of stations within Richmond Hill and Markham is shown in Figure 6-2.

Figure 6-2: Peak Demand and Existing Capacity in Markham and Richmond Hill



[8] All population projections taken from York official plan, January 2019 consolidation.
[9] Markham Municipal Energy Plan

Note that during the relatively flat load growth years to 2024 shown in Figure 6-2, incremental load growth in Richmond Hill and Markham is being supplied through a series of load transfers that end up at the recently built Vaughan #4 MTS (see Section 6.1.3, below). Likewise, the anticipated growth from 2025 to 2030 is comparatively high as it assumes a future Markham #5 MTS will begin to supply new in Vaughan, Richmond Hill, and Markham. This means that any measures to reduce peak demand in order to defer a new Markham area station would need to consider the total growth across Markham, Vaughan, and Richmond Hill.

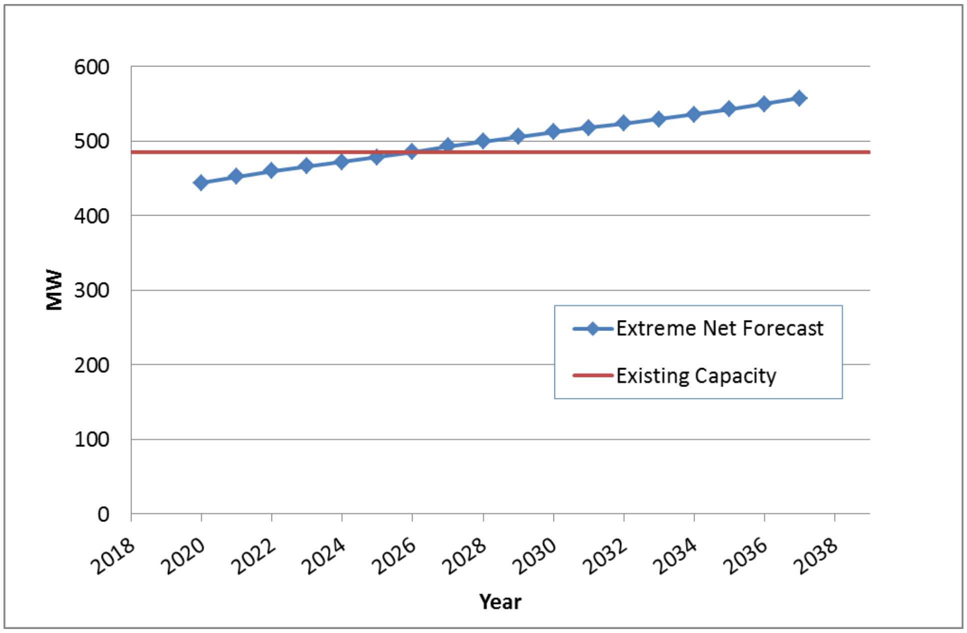
6.1.2 Northern York Region

Northern York Region is used in this IRRP to refer to customer loads currently supplied by Holland TS, Armitage TS, and Brown Hill TS. Similar to other parts of the region, it is difficult to compare municipal boundaries and electrical service boundaries. For example, a customer in eastern King township is likely to be served from Holland TS, while a customer in western King is more likely to be supplied from Kleinburg TS (which is part of a different electrical subsystem). In general terms, customers in the rapidly growing municipalities of Newmarket, Aurora, and East Gwillimbury are part of the Northern York electrical sub-region, while customers in King, Georgina and Chippewas of Georgina Island, and Whitchurch-Stouffville may be split between northern York and other electrical regions' sub-systems. Due to the long distances involved, it may not be feasible to transfer supply to some customers to infrastructure in other electrical sub-regions as a means of relieving facilities within York Region.

Out of the northern municipalities, East Gwillimbury is expected to see the highest growth over the next 20 years, with its population expected to increase from approximately 25,000 to over 85,000 by 2031. This is a significant increase, and would make East Gwillimbury similar in size by 2031 to Newmarket today.

The combined load forecasts of Holland TS and Armitage TS are shown in Figure 6-3, and roughly correspond to Newmarket, Aurora, East Gwillimbury, and parts of King and Whitchurch-Stouffville demand. Brown Hill TS is excluded from Figure 6-3.

Figure 6-3: Peak Demand and Existing Capacity in Northern York Stations



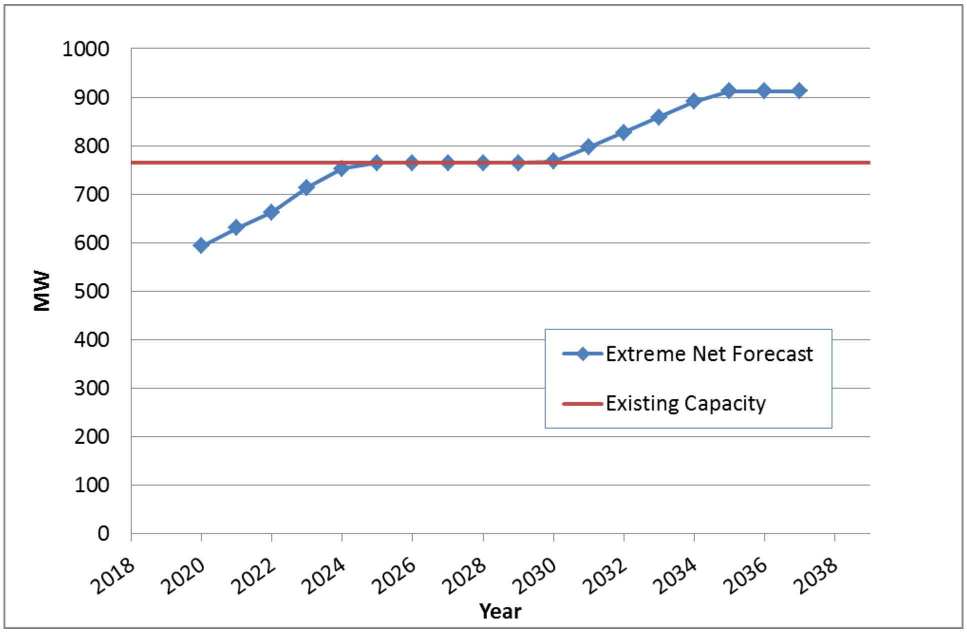
Although Brown Hill TS is part of this subsystem, at more than 20 km from Holland TS and Armitage TS, it is not close enough for load transfers. The station load is modelled in system studies to determine its impact on the grid, but it is not expected to reach its supply limit or otherwise impact needs in this study.

6.1.3 Vaughan

Similar to the situation in Markham and Richmond Hall, new growth in the city of Vaughan is increasingly being pushed further north as available land in the southern and central areas is already built up. Unlike Markham and Richmond Hill, however, Vaughan has an active transmission corridor running north through the area, which makes siting a new station close to anticipated growth centres easier.

With the addition of the new Vaughan #4 MTS in 2018, the municipality of Vaughan is the most recent to have a new step-down station come into service. Vaughan #4 MTS is located near the northernmost boundary of new growth, making this station well positioned to reliably supply the new demand. The combined load forecasts of the Vaughan stations is shown in Table 6-4.

Figure 6-4: Peak Demand and Existing Capacity of Vaughan Stations



As with the Markham forecast, demand appears flat in years where new growth is managed through transfers to a station elsewhere in southern York. For example, from 2025 to 2030, the assumption is that a new Markham station is being loaded up with new demand including Vaughan. New step-down capacity is anticipated to be required in Vaughan by 2030; however, this could be deferred through non wires measures that target peak demand growth in the area.

6.2 System Capacity Needs

System capacity refers to the amount of power that can be supplied by the regional transmission network, either by bringing power in from other parts of the province, or by generating it locally.

System capacity is evaluated by modelling power flows throughout the local grid under anticipated peak demand conditions, and applying a series of standard contingencies (outage events) as prescribed by ORTAC. Performance standards and criteria dictate how well the system must be able to operate following these contingencies. Standards at risk of not being met are identified as a system need. Since all identified system needs in York Region relate to capacity growth, they are described here as system capacity needs, for clarity.

As with station capacity needs, system capacity needs can be addressed by upgrading the system to increase load-meeting capability, or addressed or deferred by reducing peak demand.

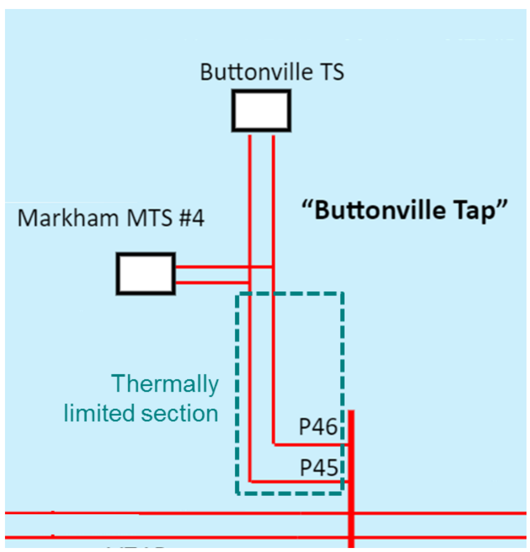
Because system assets tend to supply much larger pools of customers than any individual station, there may be more opportunities for non-wires options, but the magnitude of the need is often larger, meaning greater uptake is required over time to successfully defer system capacity needs.

Details on identified system capacity needs are described in the following sections.

6.2.1 P45/46 Supply to Markham #4 MTS

As previously identified in the Needs Assessment and Scoping Assessment, a 1.1 km section of circuit P45/46 is at risk of exceeding its thermal limit in the medium term. The P45/46 circuits extend radially north of the Parkway transformer station into Markham, where they supply the step-down stations Buttonville TS and Markham #4 MTS. These circuits are shown in Figure 6-5.

Figure 6-5: Limiting Section of P45/46, Buttonville Tap



This need is triggered when the total peak demand of Buttonville TS, Markham #4 MTS, and the future Markham #5 MTS (see Section 6.1.1) exceeds approximately 420 MW. This is forecast to occur soon after Markham #5 MTS comes into service. Note that 420 MW is an approximation as the actual loading limit can vary depending on the distribution of load between stations, for example. Power flows north of Markham #4 MTS only supply customers at Buttonville TS and possibly a future Markham #5 MTS, which means the northern section of P45/46 is not expected to hit a thermal limit unless a fourth station is connected to these circuits. This is notionally identified at the end of the 20-year forecast, but the actual need date cannot be predicted this far in advance. These dates are summarized in Table 6-1.

Table 6-1: Loading on Buttonville Tap Circuits P45 and P46

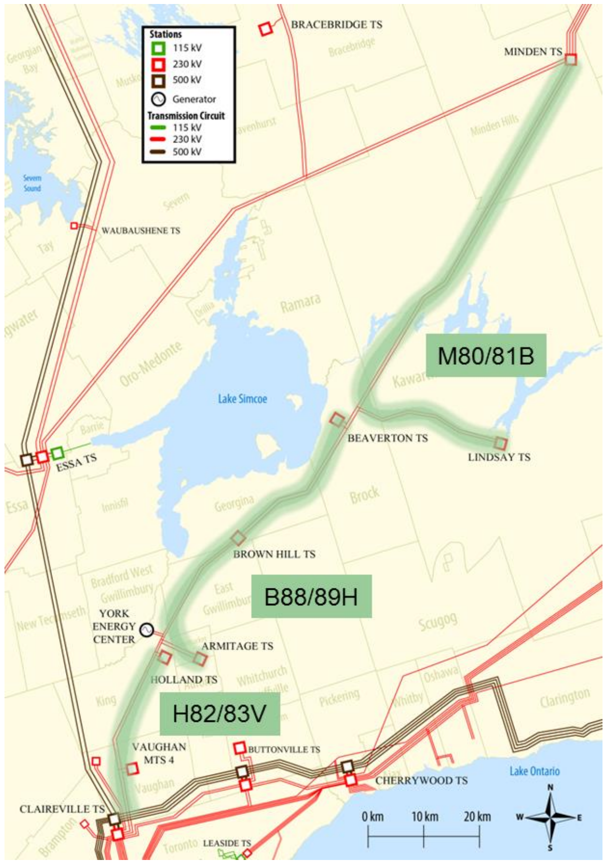
	Approx. Limit (MW)	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037
Markham #4 MTS		93	128	153	153	153	153	153	153	153	153
Buttonville TS		149	148	147	156	156	157	155	155	154	154
Markham #5 MTS		0	0	0	26	77	128	153	153	153	221
TOTAL	**420**	241	276	300	335	386	437	461	461	460	528

These needs have the potential to be deferred through non-wires measures that target peak demand in Markham (See Sections 7.1 and 7.2). Due to the meshed distribution network across Alectra's service territory in southern York, reducing peak demand across neighbouring Vaughan and Richmond Hill, combined with typical operational load transfers, can also assist in deferring this need. A relatively low-cost, low-impact wires solution has also been identified and is described in Section 7.3.1.

6.2.2 H82/83V Claireville TS to Holland TS

In the long term, continued load growth throughout York Region is expected to trigger a capacity need on the H82/83V circuits running north from Claireville TS to just south of Holland TS. These circuits are the most southerly section the transmission line that runs between Claireville TS and Minden TS. There are two sets of sectionalization devices (breakers) that divide this line into three distinct sections. The middle section, B88/89H, runs between Holland TS and Brown Hill TS and connects York Energy Centre, a critical source of supply to the area. The northernmost section, M80/81B, connects Brown Hill TS to Minden TS. The three sections are shown in Figure 6-6.

Figure 6-6: Claireville to Minden Circuits



Note that prior to 2017 there were only two sections along this corridor, with the southern section connecting Claireville TS to Brown Hill TS and referred to as B82/83V. The installation of breakers north of Holland TS was recommended in the 2015 IRRP to increase the load-meeting capability and supply security in the area, as described in Section 4.1.

Although needs emerge along different sections of this corridor at different times, it is helpful to consider the overall Claireville to Minden corridor as a single asset. Because there is no branching or redundancy along this corridor, there are limited options for alternative supply paths when a transmission outage occurs. Additionally, this corridor provides the only transmission supply path into northern York (including northern Vaughan), which means any incremental demand growth in these areas must make use of capacity on these circuits. Flows along this corridor are primarily northward from Claireville TS, which is a major bulk transmission supply point for the entire GTA. As described in Section 4.1, capacity-related needs were anticipated on this corridor during the 2005 Northern York Region Electricity Planning Study. At the time, continued growth in northern York was expected to cause northward flows from Claireville TS to exceed thermal ratings of the circuits. The recommended outcome was the addition of new dispatchable generation in northern York to reduce the amount of power that had to be transferred into the area. The resulting York Energy Centre has helped enable growth in York Region over the past decade, and is expected to continue to support local demand growth until the early 2030s.

The sections below summarize anticipated needs along this corridor over the 20-year study period.

Thermal Needs

Given the load forecast and system assumptions used in this study, thermal capacity needs have the potential to emerge in 2033 along the southernmost section of H82/83V, between Claireville TS and Vaughan #4 MTS. By 2033, the total combined load of Vaughan #4 MTS, Holland TS, Armitage TS, Brown Hill TS,[10] and possible future stations will exceed 850 MW. While the distribution of loads between stations, the eventual location of new stations and other factors influencing the actual loading limit of the Claireville to Minden circuits, make an exact loading limit difficult to predict this far in advance, an 850 MW limit is a reasonable assumption. The total combined load for these stations is shown in Table 6-2, with loads in excess of the assumed thermal limit highlighted.

Table 6-2: Loading on Claireville to Minden Circuits (Claireville TS to Brown Hill TS)

	Approx. Limit (MW)	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037
Vaughan #4 MTS		49	63	108	153	153	152	153	153	153	153
Holland TS		139	145	154	166	168	168	168	168	168	168
Armitage TS		297	307	312	312	317	317	317	317	317	317
Brown Hill TS		93	95	95	96	97	98	99	99	100	101
Northern York TS		0	0	0	0	8	21	33	45	58	72
Vaughan #5 MTS		0	0	0	0	0	0	32	94	147	147
TOTAL	850	578	610	670	727	742	756	801	875	943	959

The most limiting contingency observed in the assessment is the failure of either breaker north of Holland TS: L82L88 or L83L89. These contingencies cause either H82V and B88H, or H83V

[10] Although this corridor also serves Beaverton TS and Lindsay TS, these step-down stations are typically supplied by primarily southward flows from Minden TS. They are also not expected to see the type of demand increase anticipated for the stations included in this study, and therefore have limited impact on this system limit.

and B89H, respectively, to be removed from service. Following this outage, a single circuit remains available for supplying all stations between Claireville TS and Brown Hill TS, roughly twice the usual load level carried by each circuit when the companion is available. As peak demand increases across the area, thermal limits risk being exceeded under a wider range of outage contingencies, and will impact more customers.

Voltage Drop

In addition to thermal needs, a risk of post-contingency voltage drop in excess of 10% is also observed beginning in 2035 following the double circuit loss of H82/83V. Sudden voltage drops of this magnitude negatively impact power quality, especially for some voltage-sensitive industrial loads. In extreme cases, they can cause a “cascading” outage, where the voltage drop causes protection equipment to activate, disconnecting sections of the grid, and, in turn, producing additional voltage drops. These scenarios are more common on radial networks (connection at only one end of a circuit), especially over long distances and under heavy load conditions. This is the case following the loss of H82/83V, which provides the southern link to Claireville TS, as a significant portion of northern York customers would be left supplied by a 130 km radial link from Minden TS. This would be exacerbated by the simultaneous loss of generation support from York Energy Centre, whose station service is normally supplied via the distribution network fed from H82/83V. Under this contingency, in which this generation resource could be beneficial to supporting the system voltage, it would be left unavailable as currently configured.

Voltage Rise

A voltage rise phenomenon is also forecast beginning in year 2025 following the double circuit loss of B88/89H. Under high load conditions, the sudden loss of the major load centres supplied by Armitage TS and Brown Hill TS cause voltage on the remaining lightly loaded circuits of M80/81B to exceed 250 kV. This is above acceptable voltage levels for a 230 kV circuit. Part of the cause of this phenomenon is the use of capacitor banks at Lindsay TS and Beaverton TS to keep voltage on B88/89H from dropping after the double loss of H82/83V or the single loss of either B88H or B89H. If, however, a double circuit contingency occurs for B88/89H instead, the capacitor banks intended to keep voltage from dropping will instead contribute to excess voltage rise.

Summary of Needs

Three other considerations are important for understanding the capacity-related needs described in this section.

1) Multiple capacity-related needs are triggered in short succession. Although the need date (2033) is based on thermal limits following a specific contingency, other criteria would likely be violated shortly thereafter, including voltage drop and security of supply in 2035 (see Section 6.3.2, below). Restoration needs are also forecast to emerge as soon as 2020, meaning that solutions should be evaluated based on their ability to meet all identified needs, instead of just the most limiting or first to appear.

2) Although thermal needs do not emerge until 2033, this requires making use of a Special Protection Scheme (e.g., Load Rejection) in the interim. Under high load conditions, a predetermined set of automatic control actions will disconnect customer load following specific combinations of transmission outages and generation operation assumptions to ensure post-contingency thermal and voltage limits can be respected. This is in addition to customers who lose power due to loss of supply to their station (referred to as loss by configuration). Although load rejection is an acceptable control action under ORTAC criteria, where low-cost options exist to reduce the risk of exposure to customer outages, they should be investigated to determine if the expected benefit exceeds the upgrade cost. Other concerns with the Special Protection Scheme (SPS) operation include the frequency with which it must be manually armed by operators, estimated at hundreds of times per year by the time security needs are triggered.[11] This operational risk, in addition to thermal, voltage, and security criteria, is described in greater detail in the Holland TS 230 kV breaker System Impact Assessment, completed in 2016.

3) Once triggered, the magnitude of this capacity need increases very quickly. This happens because both the future Northern York and Vaughan stations are expected to be connected to the Claireville to Brown Hill circuits, as they provide the only transmission supply to northern Vaughan and northern York. When load transfers from Markham and Richmond Hill to Vaughan are accounted for, virtually all incremental load growth in York Region is being supplied from this same transmission line by the early to mid-2030s. This has implications for how long NWAs will be a feasible or cost-effective measure to defer new infrastructure, and the degree to which they can form part of the solution.

4) Additional potential needs exist outside of those covered by planning criteria. The needs identified in this section are based on the application of standard criteria as described in ORTAC. However, the transmitter has expressed additional concerns regarding the challenge of

[11] SIA assessment was performed using the load forecast from the 2015 IRRP. Conclusions should be read based on MW loading rather than year, given updates to the forecast in the current IRRP.

planning for circuit outages to perform routine maintenance. These outages are typically planned during periods of low expected demand, out of consideration for the remaining assets which must supply a larger share of power during the outage period. As loads continue to increase on this corridor, the available window for securing outages will be reduced, potentially risking deferral of routine maintenance activities, or requiring York Energy Centre to dispatch more frequently to reduce transmission flows. The IESO will continue to work with Hydro One to identify appropriate maintenance periods and ensure system reliability during these times.

6.3 Supply Security and Restoration

Supply security and restoration refer to the electricity transmission system's ability to minimize the impact of potential supply interruptions in the event of a contingency, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the maximum limit of load interruption that is permissible in the event of a transmission outage considered for planning. Based on past planning practices in Ontario, the supply security limit is 600 MW for two transmission elements out of service. Load restoration describes the electricity system's ability to restore power to a customer affected by a transmission outage within specified time frames. Both transmission and distribution (transfer) measures are considered when evaluating restoration capability.

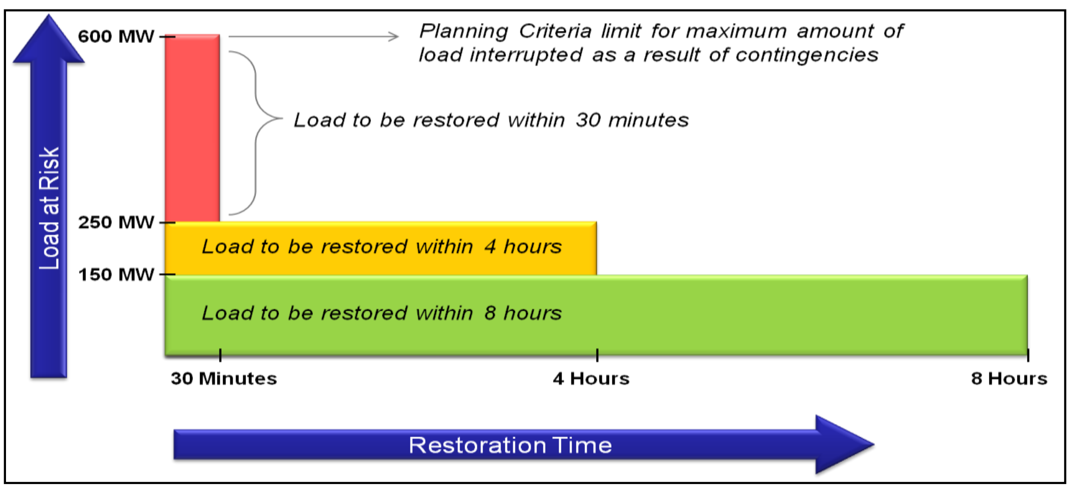
Specific requirements can be found in ORTAC, Section 7, Load Security and Restoration Criteria. The load security criteria can be found in Section 7.1 of ORTAC, and a summary of the load security criteria can be found in Table 6-3. All transformer stations in York Region have at least a dual transmission supply, which allows the load served at the station to remain uninterrupted in the event of a single-element contingency. As a result, there are no risks associated with the loss of a single transmission element. Supply interruptions may occur after multiple-element contingencies, but under all possible interruption scenarios, the amount of load interrupted was found in the assessment to remain within the limits prescribed in ORTAC.

Table 6-3: Load Security Criteria

Number of transmission elements out of service	Local generation outage?	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted by configuration, load rejection, and/or curtailment
One	No	≤ 150 MW	None	≤ 150 MW
	Yes	≤ 150 MW	≤ 150 MW [12]	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
	Yes	≤ 600 MW	≤ 600 MW[12]	≤ 600 MW

Described in Section 7.2 of the ORTAC, load restoration criteria specify that the transmission system must be planned such that, following design criteria contingencies, all interrupted load must be restored within approximately eight hours. When the load interrupted is greater than 150 MW, the amount of load in excess of 150 MW must be restored within approximately four hours. When the load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within 30 minutes. A visual representation of the load restoration criteria is shown in Figure 6-7.

Figure 6-7: Load Restoration Criteria



Technically feasible solutions to address restoration or supply security needs usually consist of wires-type investments to sectionalize or introduce greater redundancy in the existing system. Sectionalization measures, such as adding switches or breakers, can reduce the area exposed to

[12] Up to the local generation outage amount, which in this area is 187 MW.

an outage, or allow for parts of the affected circuit to be restored more quickly. Greater redundancy, through new links on the transmission or distribution network, provides additional paths that can limit exposure to outages, and improve supply-meeting capability for the local system.

Due to the meshed distribution network, southern parts of York Region (roughly the municipalities of Vaughan, Markham, and Richmond Hill) generally perform well for restoration assessments, as significant transfer capability exists between adjacent station service territories by utilizing capability of the distribution network. The areas of risk for restoration-related issues are generally the northern part of York Region, including the service territories of Kleinburg TS, Holland TS, Armitage TS, and Brown Hill TS. Additionally, a security risk was identified in Northern York.

Given the proximity to repair crew and equipment, it is assumed that a transmission outage in this area can generally be restored within eight hours. As a result, restoration assessments for York Region focus on the 30-minute and four-hour milestones. Restoration capability was determined based on discussions with LDCs, which provided expected transfer capabilities and times following a total loss of station supply.

6.3.1 Kleinburg Radial Tap (V43/44)

As identified in the Needs Assessment and Scoping Assessment, the loads supplied by the V43/44 radial circuits extending north from Claireville along the western edge of Vaughan are at risk of not meeting restoration guidelines defined by ORTAC. Following the loss of these two circuits, supply is interrupted to the step-down stations of Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS. In addition to supplying customers from the municipalities of Vaughan, King, and Caledon, these three stations also supply some load from Brampton, Toronto, and Mississauga. Table 6-4 shows the maximum interrupted load (total peak demand), as well as the amount at risk of not being restored within 30 minutes and four hours.

Table 6-4: Loss of V43/44, MW

	Limit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037
Interrupted	600	418	434	446	447	452	454	473	473	473	475
Remaining after 30 minutes	250	290	299	306	308	310	312	331	331	332	334
Remaining after 4 hours	150	93	95	96	97	98	99	119	119	120	122

6.3.2 Northern York (H82/83V and B88/89H)

Both the B88/89H and H82/83V circuits supply load in northern York, where the longer distances often make restoration through the distribution network more challenging. The addition of breakers and switching devices at Holland TS in 2017 mean that following a double outage of either B88/89H or H82/83V, supply can be restored to either Holland TS or Armitage TS, respectively. However, supplying Holland TS from B88/89H during peak demand periods would require York Energy Centre to be operational to maintain voltage support in the area. Since it may take over an hour for York Energy Centre station service to shift from Holland TS to B88H and return to service after the total loss of H82/83V, restoration of Holland TS is assumed by the four-hour mark. Restoration of Armitage TS is possible within 30 minutes.

Following a loss of the northern section, B88/89H, all load at Armitage TS, Brown Hill TS, and the future Northern York TS would be lost. However, since Armitage TS can be restored within 30 minutes, load loss does not exceed ORTAC standards within the study period.

Following a loss of the southern section, H82/83V, all load at Vaughan #4 MTS, Holland TS, and the future Vaughan #5 MTS would be lost. Additionally, as mentioned in Section 6.2.2, this outage may trigger operation of an SPS, which would automatically disconnect customer load at Armitage TS and Brown Hill TS during peak load periods to ensure voltage remains within acceptable limits. This action is not permitted to interrupt more than 150 MW of customer load. Restoring Holland TS by shifting supply to B88/89H is assumed to occur at the four-hour mark, as York Energy Centre must be operable to ensure sufficient voltage support. The delay from 30 minutes (typical switching operation time) to four hours may trigger restoration needs beginning in 2020. Table 6-6 shows the maximum interrupted load (total peak demand), as well as the amount at risk of not being restored within 30 minutes and four-hour time frames.

Table 6-5: Loss of H82/83V (MW)

	Limit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037
Loss by configuration		188	208	262	319	321	320	353	415	468	468
Estimated loss by SPS		86	96	101	101	113	126	138	150	>150	>150
TOTAL Interrupted	600	274	304	363	420	434	447	491	565	>600	>600
Remaining after 30 minutes	250	249	272	309	343	358	370	399	441	468	468
Remaining after four hours	150	0	0	0	0	0	0	0	0	0	0

The table also highlights the expected customer exposure to load rejection due to the SPS. This was estimated by taking the maximum load supplied on B88/89H when the maximum 150 MW load rejection is required to keep voltage drop within acceptable limits following the loss of H82/83V. This occurs in 2033. For earlier years, the 150 MW load rejection is reduced to keep post-contingency demand on B88/89H flat at 2033 levels. However, by 2035 the 150 MW load rejection cannot be relied upon, as it would push total interrupted load (by configuration and SPS) to more than 600 MW, exceeding maximum supply security limits. This means that by 2035 either supply security limits will be exceeded by rejecting more load than is permitted, or voltage drop limits will be reached. In either case, a system need is triggered in 2035.

6.4 Summary of Identified Needs

Table 6-7 outlines the needs identified in this IRRP, according to whether they are expected to emerge in the near, medium, or long term. The next section of the report will consider the types of solutions considered to address needs in general terms, and describe the evaluation of alternatives.

Table 6-6: Summary of Identified Needs

Need	Details	Expected Timing
Near-Term Needs		
Restoration and supply security needs	Supply security needs have previously been identified for the V71/75P Parkway corridor. Restoration needs also exist on the Kleinburg radial pocket (V43/44), and may emerge shortly (2020) in Northern York (H82/83V)	Existing
Medium-Term Needs		
H82/83V Claireville TS to Holland TS	Voltage rise on stations along M80/81B following loss of B88/89H	2025
Markham area step-down station capacity need	Loading at existing Markham area stations exceeded under basecase forecast. Need for new Markham #5 MTS triggered	2025

Northern York area step-down station capacity need	Loading at existing Armitage TS and Holland TS exceeded under basecase forecast. Need for new Northern York TS triggered	2027
P45/46 (Parkway TS to Markham #4 MTS)	System capacity need. Thermal limits are exceeded on the circuits between Parkway MTS and Markham #4 MTS, a 1.5 km section of the Buttonville Tap	2029
Vaughan area step-down station capacity need	Loading at existing Vaughan area stations exceeded under basecase forecast. Need for new Vaughan #5 MTS triggered	2030
Long-Term Needs		
H82/83V Claireville TS to Holland TS	System capacity need. Thermal, voltage drop, and supply security needs triggered in quick succession	2033

7. Plan Options and Recommendations

This section outlines the options considered to address transmission needs in York Region, including how these options were evaluated and the recommendations for action in the near-term.

There are generally two types of approaches for addressing the types of growth-related capacity needs observed in this area:

1. Target measures to reduce peak demand to maintain loading within the system's existing limits
2. Build new infrastructure to increase the load-meeting capability of the area

Distributed energy resources, including demand response, EE measures, or energy storage are well suited to the first approach, and are considered first.

Even if not being pursued to address specific system capacity needs, there are other potential benefits to non-wires investments, such as customer cost savings, and reducing GHG emissions. Some of these other objectives have been identified in municipal energy plans. The information in this IRRP may be a useful source of input for identifying the potential for projects and strategies at the local level, while identifying where electrical system benefits and infrastructure deferral value may also exist. Information on avoided costs from a provincial grid perspective (e.g., avoided energy and capacity) is presented in the Annual Planning Outlook (APO), released in January 2020. System avoided cost values are updated periodically by the IESO.

Where reducing peak demand is not technically or economically feasible, the other strategy is to upgrade the infrastructure to increase the load-meeting capacity of the area. The types of upgrades that are viable can depend on the nature of the need. In cases where a step-down station exceeds its maximum capacity, a station can be expanded or built if the transmission has sufficient capability to supply it. If the transmission system is at its capacity, generally the options are to build new local generation (to reduce the amount of power that needs to be brought in from elsewhere), or to build new or upgrade the transmission to increase transfer capability. New transmission also has the potential to improve security and restoration by adding redundant supply paths, as additional redundancy reduces exposure to outages when a transmission element is out of service.

7.1 Energy-Efficiency Opportunities and Options

Since the 2019-2020 Interim Framework took effect on April 1, 2019, the IESO has been mandated to centrally deliver province-wide EE programs that target businesses, Indigenous communities and low-income consumers. Through the Framework, the IESO offers EE incentives and rebates to electricity customers through a suite of Save on Energy programs, which provide a valuable and cost-effective system resource that helps customers better manage their energy costs.

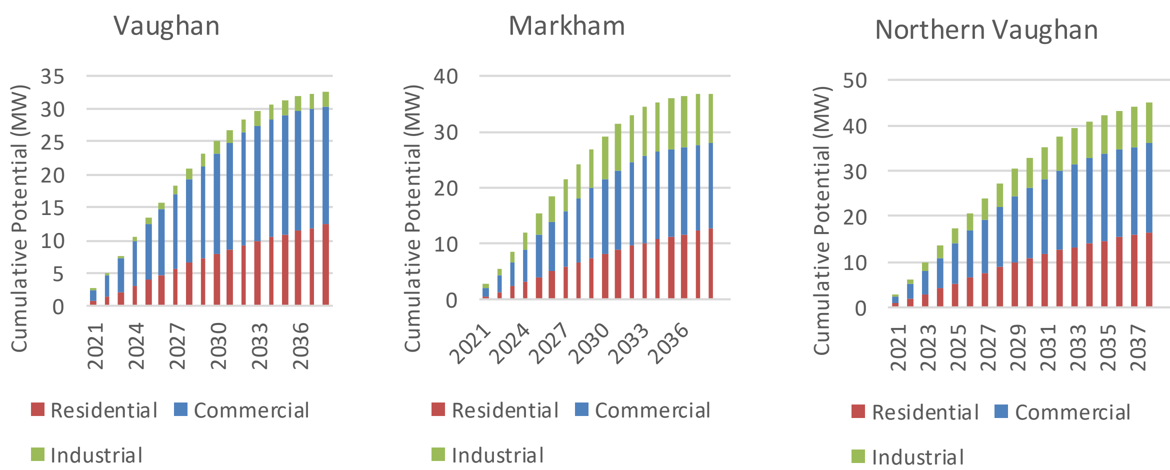
The IESO is currently working with government and stakeholders to consider opportunities for EE in Ontario beyond 2020. In 2019, the IESO completed an integrated electricity and natural gas conservation achievable potential study (2019 APS) in partnership with the Ontario Energy Board. The 2019 APS identified significant and sustained potential for EE across all customer sectors throughout the study period.

EE investment decisions are typically determined by assessing the cost-effectiveness of the initiative (i.e., whether the incentive costs are outweighed by the benefits to the electricity system). Some value is attributed to non-energy benefits, such as customer comfort or improved business productivity. The 2019 APS results were used to estimate EE opportunities within York Region that are cost effective from the system perspective.

Figure 7-1 shows the total estimated potential for cost-effective EE to reduce summer peak demand[13] in the Vaughan, Markham and Northern Vaughan areas.

[13] The 2019 APS defined the summer peak period as June-August between the hours of 1 p.m. and 7 p.m., which for the purposes of this analysis are considered to be reasonably aligned with York Region system needs.

Figure 7-1: Cumulative System Energy-Efficiency Potential to Reduce Peak Summer Demand



As described in Section 6.1, growth forecasts show a potential mid-term need for up to three new step-down stations in York Region, including a Markham #5 MTS in 2025, a Northern York TS in approximately 2027, and a Vaughan #5 MTS in approximately 2030. Additionally, an anticipated long-term need for additional system capacity along the Claireville-Minden circuits is expected in 2033 or later. As noted above, the dates for capacity-related needs (station or system) could be deferred by NWAs, such as EE, that target peak demand electricity use.

In particular, energy-efficiency initiatives targeting peak demand within the municipalities of Vaughan, Richmond Hill, and Markham have the potential to defer the need dates for Markham #5 MTS and Vaughan #5 MTS. Measures targeting the higher-growth northern municipalities of Newmarket, East Gwillimbury and Aurora would likely be the most effective at deferring the Northern York TS. Any measure introduced within York Region has the potential to defer the long-term system capacity need.

Table 7-1 shows the estimated impact on the need date for medium and long-term capacity needs in the area, assuming 50% achievement of the economic EE potential, and 100% achievement.

Table 7-1: Impact of Energy Efficiency Achievement on Capacity Need Dates

Capacity Need	Existing need date (current forecast)	Estimated deferred need date	
		50% Economic EE	100% Economic EE
Markham #5 MTS	2025	2025	2026
Northern York TS	2027	2029	2033
Vaughan #5 MTS	2030	2031	2032
H82/83V Claireville TS to Holland TS	2033	2034	2036

While the rapid growth in this region may limit the potential for EE to fully meet forecast needs, the medium to longer-term nature of the needs present an opportunity to target as much of the system cost-effective EE potential as possible in the near term. The time available still allows for evaluation and monitoring the impact on load growth between regional planning cycles and into the next planning cycle. See 1.1.1Appendix C: Options and Assumptions**Error! Reference source not found.** for more information about the methodology used to calculate EE potential.

7.2 Distributed Energy Resource Opportunities and Options

DERs, as well as other NWAs, were considered to address the long-term needs identified in the IRRP. Potential resource solutions consisted of distribution-connected technologies, taking into account the nature, magnitude and profile of the need. In terms of the resource solution, options considered included: lithium battery energy storage, solar PV generation, a combination of solar and lithium battery energy storage. Larger resource options were also considered, including natural gas-fired SCGT. The cost trends and projections associated with these technologies were assessed.

Consistent with previous IRRPs, an economic analysis of the alternatives and the lowest-cost option and combination of options were compared based on net present value (NPV). Lithium battery energy storage was ruled out as a viable option due to the significant size of the need. The capacity contribution of solar resources for peak demand reduction is estimated to range between 13.8% and 30% (refer to Figure 4.2 in the December 2019 Reliability Outlook tables); therefore, the cost of solar PV would increase significantly to install the effective capacity required. Based on the prevailing technology costs, SCGT would be the least cost resource alternative.[14]

One of the traditional barriers to developing DERs at a large enough scale to address transmission system constraints is the challenge in predicting how well resource availability will match the time of day and duration of system needs. In order to better understand the ability of DERs to target peak demand periods, and defer new transmission infrastructure, the IESO has launched a two-year local electricity market demonstration project in southern York Region.

The local electricity market demonstration will allow DERs like solar PV, energy storage, and consumer demand response, to compete to provide local solutions when they are needed. This project is expected to provide data to demonstrate how these types of resources can offset peak demand periods, and the associated costs, reliability, and operation. The capacity target is proposed to be 10 MW in a 2020 auction and 20 MW in a 2021 auction. The 2021 auction will be subject to revision after the first auction. Further design elements and considerations are available on the IESO's website.

Funding for the pilot comes from the IESO's Grid Innovation Fund and Natural Resources Canada (NRCan)'s Smart Grid Fund. Alectra, the local distribution company for the region, will help deliver the pilot program, which is expected to get underway in Q2 of 2020.

7.3 Wires Options

The term "wires" option refers to any conventional transmission or large-scale resource solution used to increase the load-meeting capability of an area.

In the near term, a relatively minor need related to the P45/46 circuits can be addressed through reconductoring of an existing line. In the medium to long term, more significant wires upgrades may be required, including up to three new step-down stations, and a system capacity upgrade for the Claireville to Minden circuits. An opportunity has also been identified to improve system reliability, operability, and resource availability by advancing the reconfiguration of

[14] The estimated overnight cost of capital assumed is about $1,445/kW (2019 $CAD), based on escalating values from a previous study independently conducted for the IESO.

York Energy Centre's station service supply point. This work would otherwise be required in the long term to address supply security.

7.3.1 Reconductor P45/46

Hydro One has previously indicated that the existing transmission towers serving this area are capable of supporting higher-rated conductors, which will raise the load-meeting capability from approximately 420 to 600 MW. The new limit would be based on supply security for the loss of both circuits. This measure is expected to cost approximately $2 million, and can be implemented with a three-year lead time. Alternatives to reconductoring would include building a new supply path to remove Markham #4 MTS from the limited P45/46 circuits, and instead provide supply from the C35/36P (Parkway) circuits. Since this alternative would be more costly (minimum $5 million), take longer, and be more disruptive to the local community, the lower-cost, less intrusive alternative is recommended.

Based on the peak demand forecast, reconductoring of the limiting transmission section is required to be complete in 2029, or a few years after Markham #5 MTS comes into service. However, since newly commissioned stations often receive large transfers to assist in load balancing, the Technical Working Group recommends that the need date be based on the Markham #5 MTS in-service date, and that Hydro One proceed with design work following the completion of this IRRP to ensure the upgrade can be in place before Markham #5 MTS comes into service (currently forecast for 2025).

In addition to the near-term need identified above, a similar long-term need may arise along the remaining Markham #4 MTS to Buttonville TS section of the same P45/46 circuit, beginning if and when a second new step-down station is required in the Markham area (notionally Markham #6 MTS). Based on the current load forecast, this is not expected to occur until the late 2030s, and has the potential to be deferred through EE and other non-wires measures targeting peak demand throughout the southern York municipalities. Given the uncertainty surrounding the longer-term need for reconductoring the remaining 2.7 km of these circuits, there is little benefit from advancing the need dates and performing the upgrades on the entire circuit at this time.

7.3.2 Address the Potential for High Voltages on M80/81B

The voltage rise described in Section 6.2.2 is forecast to trigger a need at the stations connected to the M80/81B circuits beginning in 2025. There are many relatively straightforward ways this need can be addressed. For example, a Special Protection Scheme (or Remedial Action Scheme) could automatically remove capacitor banks at Lindsay TS and Beaverton TS under high load conditions following the double circuit loss of B88/89H. The Working Group recommends that Hydro One investigate this need, identify a preferred solution through the RIP process, and implement that solution no later than 2025.

7.3.3 Reconfiguration of Station Service Supply for York Energy Centre

The York Energy Centre supplies power to the B88/89H circuits through a connection north of the Holland breakers. However, the station service (necessary for operating station equipment) is fed under normal conditions from the distribution network via Holland TS, which is located south of the Holland breakers. This means that following the loss of H82/83V south of Holland TS, which leaves Brown Hill TS, Armitage TS, and the future Northern York Region TS supplied radially from the north, York Energy Centre would also be removed from service. This outage, described in Section 6.2.2, causes risks associated with restoration in the near term, and voltage drop and supply security risks in the medium to long term.

If York Energy Centre could remain in service throughout this outage, voltage drop would be addressed without the need for load rejection, and the supply security risk would be avoided. Additionally, Holland TS could be transferred to B88/89H within 30 minutes, also addressing the near-term restoration need (load >250 MW restored within 30 minutes). This could be accomplished by ensuring normal station service supply is provided at a point north of the Holland breakers. An alternate station service supply point does exist, and is fed via the B88H circuit. However, normal operation from B88H would create a new risk for loss of York Energy Centre following a single B88H contingency. This would create similar thermal and voltage issues in Northern York beginning in 2025, and also require operation of load rejection through a Special Protection Scheme. In order to address both sets of needs, future York Energy Centre station service supply would need to ensure continuous operation following the loss of both H82/83V circuits, or the loss of either B88H or B89H.

Upgrading York Energy Centre station service to ensure operation following the loss of both H82/83V circuits, or the loss of either B88H or B89H, could be accomplished several different ways. One option is to make use of the two existing supply paths, but connected through an

Automatic Transfer Scheme, which automatically switches from one source to another immediately after a supply interruption is detected, without impacting station operation. Another option would be to add a second transmission supply point off of the B89H circuit. Alternatively, technologies such as battery storage could enable the instantaneous transfer of station service supply at the facility, with the added benefit of improving voltage stability in off-peak hours, and regulation service for the system.

Estimating the cost of these types of upgrades would require a more detailed review of York Energy Centre's existing station service configuration, including spatial layout and protections operation. Transmission alternatives could include converting Holland Junction into a full switching station (SS), or advancing the construction and specifically siting the future Northern York TS in a location suitable for supplying normal station service. The latter alternative, while addressing the simultaneous H82/83V contingency, would still expose York Energy Centre to interruption following a distribution-level outage (unless implemented in addition to an Automatic Transfer Scheme).

Under the peak demand forecast, reconfiguration of York Energy Centre station service is required no later than 2035 to address supply security and voltage drop needs. However, advancing this upgrade would benefit local customers immediately by lowering exposure to supply interruption or power quality issues under specific outage conditions. This includes eliminating the risk of a restoration need beginning in 2020. Additionally, increasing the availability of system resources under a greater range of outage conditions, including the loss of H82/83V, B88H, or distribution supply, would benefit a wider range of customers. As a result, this IRRP recommends that the IESO and Capital Power (York Energy Centre's operator and 50% owner) proceed with a more detailed investigation to identify and consider options for a preferred long-term station service supply configuration, including estimated cost impact. These discussions may include Hydro One, as necessary.

7.3.4 New Step-down Transformer Stations

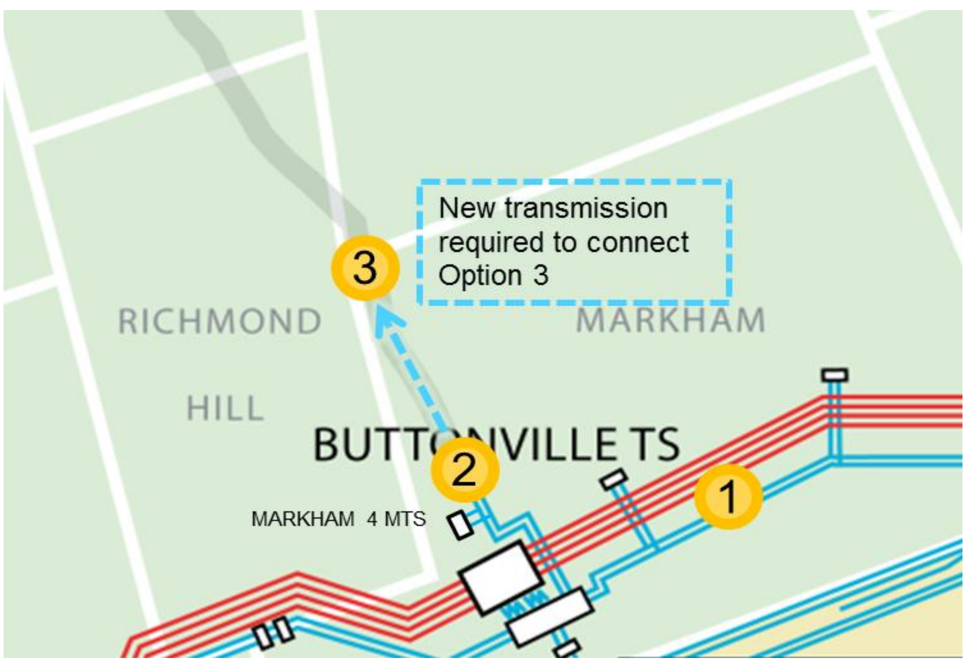
Based on the demand outlook, three areas in York Region may require new step-down station capacity in the medium term. Due to the timelines associated with these needs, and typical station construction (around three years), action is not required at this point to advance a wires solution. Instead, station loadings continue to be monitored to determine the pace of growth, net of EE and DER impacts. Options are described below to assist in identifying suitable locations for this infrastructure, and preserve long-term options.

Markham Area Transformer Station

Due to the meshed configuration of Alectra's southern York Region service territory, new step-down transformer stations are generally alternated between the western (Vaughan), and eastern (Markham) sides of the system. The last step-down station built to serve this area was Vaughan #4 MTS in 2018. This station is expected to be sufficient to meet growing load in southern York until approximately 2025. This means that the next step-down station should be built in Markham to keep distribution system loads balanced. Choosing a Markham location instead of Vaughan is also preferable as it does not contribute to the long-term Claireville to Minden system capacity needs.

Alectra began investigating possible candidate locations for Markham #5 MTS during the previous IRRP, and identified three technically feasible locations, shown conceptually in Figure 7-2.

Figure 7-2: Candidate Locations of Markham #5 MTS



The primary criterion used to determine a preferred station location is generally the cost of new infrastructure required to incorporate the station to the grid and connect customers. The technical feasibility can also be used to evaluate options, and community preferences can be a factor, especially where costs of different options are otherwise similar. Because the cost of building the station is roughly the same for all three locations (around $30 million), only those costs related to incremental transmission (where required) and distribution connections that vary by location are considered. Details on these alternatives, and associated costs, are provided as follows (numbers correspond to the locations in Figure 7-2).

1. **Southeast option, connection along the Parkway**. This site is the furthest removed from the areas of anticipated growth, significantly increasing the long-term cost of distribution infrastructure to connect new customers (approximately $69 million). There is also a risk that capacity at this station could become stranded if it becomes technically infeasible to supply load concentrated along Markham's northern border, even after accounting for transfers to and from a more northern station, such as Buttonville TS. The transmission circuits along the Parkway are capable of supplying the anticipated capacity of a station at this site, and would not require any upgrades.

2. **Central option, connection at the existing Buttonville TS**. This option involves using available space at this facility to build a second step-down station adjacent to the existing Buttonville TS. Because this location is closer to the growth areas in northern Markham, distribution costs are less that the first option (estimated at $27 - $43 million). As described in Section 6.2.1, the incremental load of a new Markham #5 MTS would trigger the need to upgrade the P45/46 circuits from Parkway to Markham #4 MTS, at a cost of approximately $2 million. No further transmission work would be required to accommodate this station location.

3. **Northern option, connection via new transmission supply from Buttonville TS.** This possible location is near the northern edge of Markham, is closer to the anticipated area of highest new growth. Associated distribution costs are estimated at $17 million. Because this site is located north of the existing grid, approximately 6 km of new, double-circuit transmission line would be required. Parts of an existing transmission corridor containing an idle 115 kV line could be leveraged, but this would require replacing the existing towers with larger, 230 kV-rated towers. Additionally, most of the required 6 km of this corridor is adjacent to residential built up areas. Previous plans considered rebuilding this corridor as an option to improve supply capacity to the area, but this resulted in community opposition (see Section 4.1). As with option 2, locating Markham #5 MTS north of Buttonville TS would also trigger the $2 million upgrade of conductors on the P45/46 circuits between Parkway and Markham #4 MTS.

Of these three options, the southeast alternative was rejected, as it performs much worse in terms of distribution costs than the central site, while introducing a risk of stranding assets in the long run. Selecting a preferred site between the central and northern options is more challenging. Both rely on capacity from the Parkway to Buttonville circuits to supply new customers in northern Markham, but one relies on transmission to access new customers, and the other distribution. In order to identify the least-cost outcome, these two sets of incremental costs are compared in Table 7-2. Since both options require the upgrading of the P45/46 circuits between Parkway TS to Markham #4 MTS, this cost is omitted from the analysis.

Table 7-2: Distribution Costs Associated with Candidate Markham #5 MTS Locations

Location	Approximate cost of distribution infrastructure ($million)
1. Southeast Option (rejected)	$69
2. Central Option (Buttonville TS)	$27 - $43
3. Northern Option	$17
Difference between Central and Northern	**$10 - $26**

The distribution costs reflect the uncertainty associated with the location and type of new connections that may be required. For example, distribution cost associated with the Central station may range from $10 million to $26 million more than the Northern station.

Predicting the transmission cost of extending the Buttonville radial tap an additional 6 km into northern Markham requires making assumptions about the type of technology being used:

1. Overhead towers. These are the most common, least-cost type of transmission technology. Costs can vary depending on site topology and tower design, but are estimated for this extension to be around $21 - 27 million. Suitability of the terrain and community preference will determine what type of tower design can be accommodated.

2. Underground cables. The use of underground cables is typically reserved for cases where overhead transmission is not technically feasible, such as when insufficient right-of-way space exists. Costs are significantly higher for this extension at approximately $102 million. Cables also typically have a shorter lifespan, requiring replacement after about 40 years, while most overhead circuits can last 60 years or longer. Additionally, although the likelihood of outages for cables is lower than overhead transmission (less risk from weather or animal contact), when they occur, these outages generally last longer before they can be isolated and repaired.

If this transmission extension were being considered as a stand-alone solution to enable the Northern Markham #5 MTS location, the costs above could be compared directly to the incremental distribution costs associated with the Central location. However, as described in

Section 6.2.2, there is also a long-term need to increase the load-meeting capability of the Claireville to Minden circuits. One identified option (described in greater detail in Section 7.3.5), is to rebuild the entire Buttonville to Armitage right of way to 230 kV, which includes the section needed for accessing the Northern Markham #5 MTS location. The Buttonville to Armitage option is one possible alternative. If it is ultimately selected as the preferred long-term solution, then the actual cost attributable to the Northern Markham step-down station is only the cost of advancing the southern portion of the line from 2033 up to 2025. This advancement is the difference between the estimated need date for system capacity, versus the date for Markham #5 MTS. This creates four transmission cost scenarios: one of two technology types (overhead or cable), and one of two cost types (total cost or the advancement cost only). Because the costs are triggered in different time frames, the scenarios are expressed in NPV to assist in the comparison in Table 7-3.

Table 7-3: NPV Comparison of Markham #5 MTS Options

	Buttonville to Armitage is NOT chosen as preferred long-term capacity solution (NPV in $2019 CAD)		**Buttonville to Armitage is chosen as preferred long-term capacity solution (NPV in $2019 CAD)**	
	Overhead tower, total cost	Cable, total cost	Overhead tower, advancement cost	Cable, advancement cost
Incremental cost of Central Markham #5 MTS[15]	$6 M - $17 M	$6 M - $17 M	$6 M - $17 M	$6 M - $17 M
Incremental cost of Northern Markham #5 MTS	$30 M	$111 M	$8 M	$30 M

The NPV comparison shows that the least-cost option depends on the assumptions made about the corridor itself, and whether it is being triggered in the long term regardless of where Markham #5 MTS is located. In general, the high cost of cables mean that it is difficult to make a

[15] NPV of $10-$26 million spend at a constant annual amount between 2025 and 2036. No extension of transmission line included in costs.

case for advancing them, regardless of future outcomes. If overhead lines are considered, the cost of transmission is within the range of incremental distribution. When the uncertainty of planning level estimates for future transmission is considered (historically in the order of +/- 50%), the Central or Northern Markham #5 MTS options become comparable.

Where costs are this similar, community input should play a stronger role in selecting the preferred outcome. The ultimate decision should, therefore, be made between Alectra and the customer, as this IRRP recognizes no strong difference in cost between the Central and Northern Markham #5 MTS locations. To date the community has been clear that the preference is to defer the need for additional transmission in Markham for as long as possible or opt for undergrounding of the transmission line along the corridor, which would suggest the Central Markham #5 MTS is preferred. At the same time, since the station is not required until the mid-to-late 2020s, this decision can be revisited once additional engagement on the long-term supply capacity solution has taken place. If the Buttonville-Armitage solution is preferred, the cost benefit of advancing an overhead transmission line may shift the preference to the Northern site.

Northern York Area Transformer Station

The existing Northern York step-down stations of Armitage and Holland TS are located within the municipalities of Newmarket and King, in close proximity to Aurora. In determining an appropriate location for a future Northern York TS, consideration is given to where new customer growth is expected to materialize. Locating a step-down station closer to new customer demand reduces the amount of distribution infrastructure required, which can reduce cost as well as the risk of distribution-related outages.

Of the six municipalities which roughly make up the Northern York sub region, the municipality of East Gwillimbury is forecast to see the highest increase in population and employment over the next few decades. There is also currently no step-down station within the community, and power is supplied via feeders from either Newmarket or King. East Gwillimbury is also able to support a new step-down station without the construction of new transmission, as the B88/89H circuits cross through its territory. Although the final decision on a suitable location, including all associated environmental assessment work, rests with the LDC and transmitter, the York Region IRRP recognizes that East Gwillimbury is likely best suited to accommodate a future Northern York TS.

New step-down stations of this type, including real estate, typically cost around $35 million. The need for this step-down station can be deferred through non-wires measures that target peak demand. The focus would need to be in Northern York Region, particularly in higher-growth areas such as Newmarket, Aurora, and East Gwillimbury. Under the load forecast, a new northern station is currently expected to be required in 2027. Given development pressures in the area, the Working Group recommends that work be undertaken to identify and secure a suitable step-down location, regardless of the final in-service date. Once suitable land is secured, the need to begin development work would not be required until at least 2024. Actual load growth at Armitage TS and Holland TS should continue to be monitored on an annual basis to advance or defer this date, as required.

Vaughan Area Transformer Station

The most recent step-down transformer station in Vaughan, the Vaughan #4 MTS, was constructed near the intersection of Kipling Avenue and Kirby Road. This location was chosen because it is close to the area of growth in Vaughan, making it well placed to supply new customers. At the time the site was being acquired, enough land was purchased to locate two step-down transformer stations: Vaughan #4 MTS, and a future Vaughan #5 MTS. It is therefore assumed that Vaughan #5 MTS can be built at this location. With land already available, the incremental cost of building this new station is approximately $25 million.

The need for this step-down station can be deferred through non-wires measures that target peak demand in southern York, namely Vaughan, Richmond Hill, and Markham. The exact need date will coincide with when the next most recently built station, in this case the future Markham #5 MTS, is loaded to its maximum. This is not currently forecast to occur until 2030 at the earliest, and the date is sensitive to measures designed to defer both the Vaughan #5 MTS, and the earlier Markham #5 MTS. With the land for this future station already secure, and the need date over 10 years away, no further action on this option is recommended at this time.

7.3.5 Increase Supply Capacity on Claireville to Brown Hill Circuits

The assessment found in the long term, the limits of the Claireville TS to Brown Hill TS 230 kV circuits will be reached. The need emerging in the early to mid-2030s is a thermal need driven by the projected demand growth in the region. Section 7.3.3 describes a proposed solution that will address other issues identified affecting these circuits, including load restoration needs (in the near-term) and voltage issues (near the end of the planning horizon).

If a transmission is preferred, given the lead time required, a decision does not have to be made until 2025 at the earliest. Other decisions needed sooner, such as the location of a future Markham step-down station, have potential to be informed by the long-term outcome. In other words, the location of the step-down station could influence the best choice for transmission, if and when a decision on transmission is needed. As a result, this IRRP recommends that additional engagement with communities, stakeholders, and the LDCs continue between regional planning cycles to better inform decision-making.

Additionally, DERs or other non-wires options have the potential to defer both the medium-term step-down station needs, and consequently, they may help to defer the longer term transmission need. The aforementioned work that is recommended between regional planning cycles can also inform approaches that are intended to address the demand side in York Region, and potentially defer future transmission requirements, and/or the need to decide on a transmission solution.

Details on identified solutions are provided below. This list should not be considered exhaustive, and new options may be added where technically and economically feasible.

DERs

A DER solution to address supply capacity needs could consist of a number of smaller resources connected to the distribution network supplied by stations along the Claireville to Brown Hill circuits. In order to be successful, the network of resources would need to, collectively, offset any peak demand in excess of the existing load meeting capability of these lines. As described in Section 6.2.2, this is roughly 850 MW, but the exact number would need to be reevaluated closer to when the need is triggered to account for updated assumptions related to customer composition and the location of new step-down stations. Based on the current forecast, the DERs would have to be sized to reliably provide at least 120 MW, in order to meet the 2037 need. Based on the duration profile estimated for the area, a peaking event could require 770 MWh of energy over the course of 10 hours. Several additional peaking events, typically of lower duration, could also be expected throughout the year. Given the need for reliable, dispatchable operation, some storage technology would likely need to be part of a DER solution. However, current battery technologies are expensive, and cannot easily be scaled up to these magnitudes. Given that technology's current characteristics, battery energy storage would also need to be oversized. Building additional local resources to power the batteries, such as solar, would also add to the cost of this type of solution. Using existing costs, as well as cost trends and projections associated with solar PV and battery storage, an installation capable of up to 120 MW of demand, and 770 MWh of energy output, would not be cost feasible, and would likely introduce operational issues as well. However, these estimates should be revised as technologies continue to develop. In particular, smaller scale initiatives could have the potential to cost effectively defer the need for a conventional solution, especially when paired with other measures such as EE.

Other Resource Solutions

Larger scale resource solutions (e.g., generation) provide capacity locally, reducing the amount of electricity that needs to be transported into the region along transmission assets. Transmission-connected generation resources can be sized large enough to address most capacity-related needs caused by the high rates of forecasted urban growth in York Region. To be a viable standalone solution, approximately 120 MW of new, dispatchable, generation would be required by the end of the study period. Such a facility would need to be connected to the Claireville to Minden circuits (H82/83V or B88/89H) north of Vaughan #4 MTS. This also assumes that the existing 393 MW YEC remains operational throughout the plan horizon.

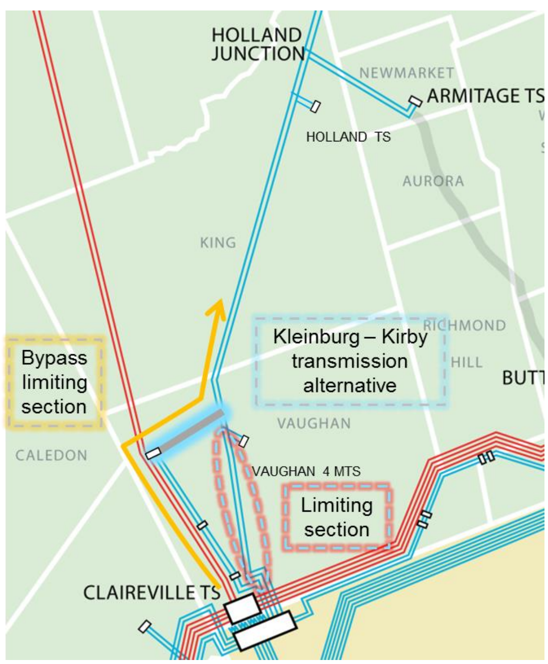
Predicting the cost of a resource solution this far in advance is challenging, as most of a resource's value comes from its contribution to system capacity, rather than local capacity needs. A purely cost-based analysis of the local generation option potentially overestimates the generation cost, since it does not credit the resource for its contribution to meeting provincial demand. If it is assumed that a simple cycle gas peaking facility were installed to address the local need only, the cost is estimated at around $270 - $300 million. However, if there is a need for (provincial) system capacity over the same time period, then the incremental cost of siting it in York Region (as opposed to elsewhere in the province) could be much less. It is not possible at this time to predict what the system value of a new resource will be in the mid-2030s. Instead, this IRRP recommends that the potential value of new capacity in this area be considered when long-term resource adequacy assessments are prepared for the 2030s. The local value of siting resources in this area can be expressed in terms of deferral value of the transmission alternatives described in the sub-sections that follow.

Compared to transmission solutions, the land use impact of the generation option is minimal, if located along the existing corridor. At the same time, the most suitable resource type for these needs at present is a gas-fired facility, as battery technology cannot be cost-effectively scaled up to the necessary size, and renewable resources are not controllable. This assumption may change over time as energy storage and other technologies improve or are introduced to the marketplace. Many municipalities in York Region have also indicated that they wish to reduce greenhouse gas emissions, which may introduce other challenges for siting gas generation and gaining community support.

Transmission Solution – New Kleinburg to Kirby Corridor

One technically feasible transmission alternative involves sectionalizing the Claireville to Brown Hill circuits with a new transmission link connected westward to the Kleinburg TS. This option would work by providing a redundant path for power flowing from Claireville TS northward into northern York, and bypass the heavily loaded and thermally limiting section of H82/83V between Claireville TS and Vaughan #4 MTS (and a future Vaughan #5 MTS location). Depending on the configuration, this alternative could reduce the load being supplied by the constrained Claireville to Brown Hill circuits by the equivalent of up to two transformer stations. In order to be effective, the point of interconnection of the new line to the Claireville to Brown Hill circuits would have to be north of Vaughan #4 MTS. This is located near Kipling Avenue and Kirby Road. This alternative is often referred to as the Kleinburg to Kirby corridor, and is highlighted in the Figure 7-3.

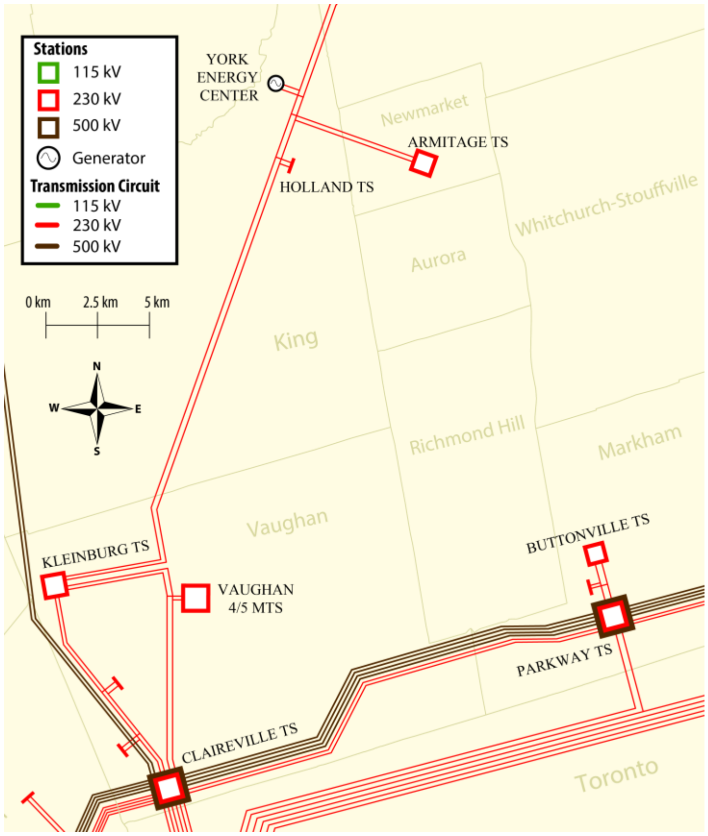
Figure 7-3: Kleinburg to Kirby Alternative



This transmission upgrade can be configured multiple ways, depending on the desired outcome for both local and provincial (bulk) system benefit. When the Kleinburg TS was originally developed, its access to both the regional 230 kV and bulk 500 kV transmission network meant it could be leveraged as a future bulk supply point, similar to Claireville TS. The station was purchased with enough land to accommodate additional switching and autotransformer facilities. If the Kleinburg to Kirby transmission upgrade is selected as the preferred option to meet York capacity needs, the ultimate configuration of Kleinburg TS should be informed by anticipated bulk system needs across the GTA at that time.

For the purpose of this study, this transmission option was modelled assuming a full switching station was built at Kleinburg, but with no autotransformers added. This was done under the assumption that the GTA West Region could have a similar capacity-related needs in the same time frame as York Region, potentially requiring additional transmission links into Kleinburg from the west. Full switching would, therefore, provide the best supply reliability for interconnecting multiple new circuits into Kleinburg from the east and west. A switching station would also need to accommodate new autotransformers, should these be required in future. For the new transmission, two double-circuit lines along the same corridor were modelled, with one terminating on the section south of Kirby Road, and the other to the north of Kirby Road. This configuration would provide significant capacity improvements for the northern section of the Claireville to Brown Hill circuits, as well as the Kleinburg radial pocket (as shown in Figure 7-4).

Figure 7-4: Possible Kleinburg TS to "Kirby Road" Configuration



Alternative configurations of the Kleinburg to Kirby transmission link which rely on one double-circuit line are feasible, but would likely require the addition of a new supply source (generation or autotransformers) at Kleinburg TS or in Northern York.

This two double circuit line alternative from Kleinburg to Kirby was found during system studies to meet all identified thermal and voltage needs over the long term. Estimating the cost of this alternative is challenging, since it requires assumptions about the eventual configuration and future bulk system needs. These are difficult to predict this far in advance. At a minimum, the cost should account for the new transmission link between Kleinburg and Kirby Road. Two conceptual double-circuit lines approximately 6 km long is estimated to cost in the range of $42 million to $54 million at the present time. While costs can vary significantly, a new switching station could cost in the range of about $110 million.

In addition to meeting thermal capacity needs, two double circuit Kleinburg to Kirby lines have the added benefits of lowering exposure to outages and improving reliability for loads served by Vaughan #4 MTS, Vaughan #5 MTS, Holland TS, and the Kleinburg radial pocket.

Specifically, with the addition of sectionalization devices, this solution could be leveraged to address restoration needs on the Kleinburg radial tap discussed in Section 6.3.1. It is also a flexible option, as new switching can be leveraged to assist other regions and the overall bulk system, and new facilities added later if required. Building the Kleinburg to Kirby transmission link may also provide valuable load-meeting capability for the neighbouring GTA West Region, which is also expected to have a step-down capacity need in the medium to long term. In terms of land use, this option would have a larger impact than the resource option described above, as it requires the development of a new, 6 km transmission corridor. The width of two double-circuit lines can vary depending on site-specific features and the technology type chosen, but 60 m is a typical assumption.

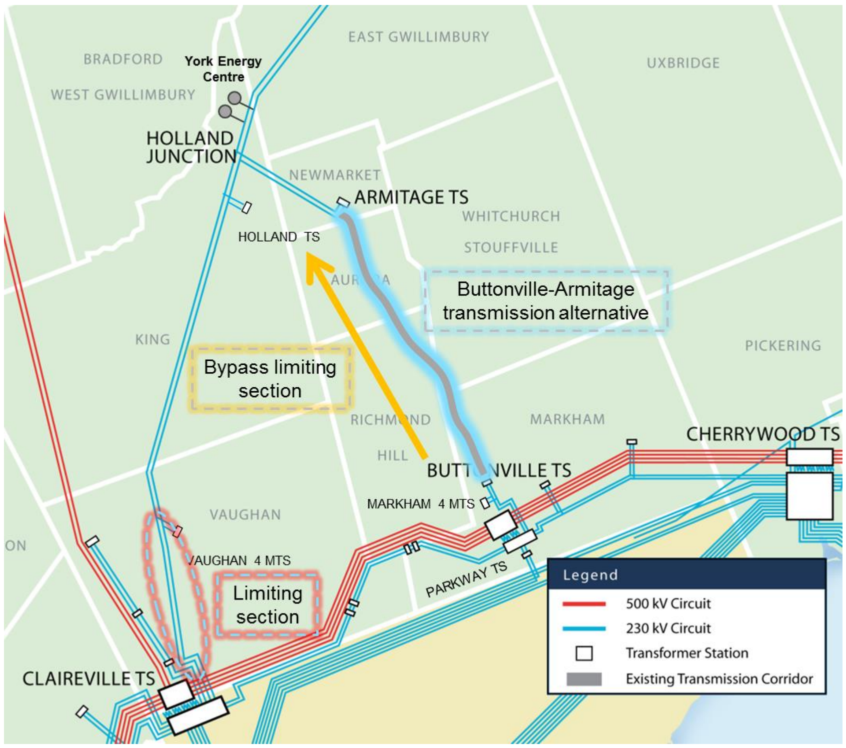
The development of a new transmission corridor along this route that has a lower impact on the land and community is currently being explored through the Northwest GTA Transmission Corridor Identification Study, a joint study being undertaken by the IESO and Ministry of Energy, Northern Development and Mines. This opportunity has emerged as a result of a separate initiative underway by the Ministry of Transportation (MTO) to develop a new 400 series highway, roughly linking Vaughan to Milton. The section of the corridor in Vaughan is ideally located to provide a potential Kleinburg to Kirby transmission link. More information on this MTO initiative is available on the website for the GTA West Transportation Corridor Route Planning and Environmental Assessment Study. In accordance with the provincial Policy Statement and good planning practice, opportunities to co-locate linear infrastructure should be pursued where feasible to do so. Co-location reduces land use impact and associated costs when planning infrastructure.

Even if the Kleinburg to Kirby supply option is not selected as the preferred approach in the long term, work to secure land for transmission will still be pursued to preserve long-term supply options in York, Peel, and Halton regions. More information on the transmission corridor initiative is available on the IESO's GTA West planning page.

Transmission Solution – Rebuild Buttonville to Armitage Corridor

This transmission solution consists of rebuilding an idle single-circuit, 115 kV transmission corridor between Buttonville TS and Armitage TS as a double-circuit 230 kV line. The total length of the rebuilt line would be approximately 20 km, and cross through sections of the municipalities of Markham, Whitchurch-Stouffville, Richmond Hill, Aurora, and Newmarket (shown in Figure 7-5).

Figure 7-5: Buttonville to Armitage Alternative



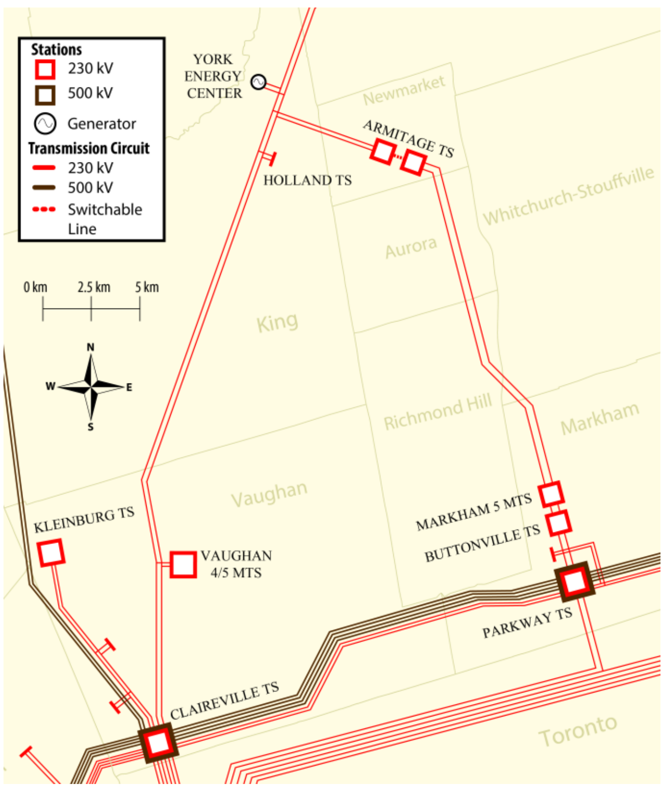
This is the same option that was considered for addressing similar capacity related needs in 2005, but was ultimately rejected in favour of a local resource-based solution. Two major factors drove this decision in 2005: opposition from the local community to redevelopment of the transmission corridor and the requirement for new generation resources to meet overall provincial electricity needs. Since these resources were to be built within Ontario anyway, the incremental cost of siting this facility in York Region was lower than the cost of this transmission upgrade.

This alternative was found during system studies to meet all identified thermal and voltage needs over the long term. It would work by creating a redundant supply path to reduce the amount of demand that needs to be served by the Claireville to Brown Hill corridor under normal operating conditions. This new circuit could also be leveraged to deliver additional restoration capability by providing alternate supply paths when faced when a transmission outage.

Similar to the Kleinburg to Kirby solution, this option could be configured to serve different system needs. At a minimum, a new double-circuit line would be required from the existing junction at Buttonville TS to Armitage TS, in central Newmarket. A full switching station is not assumed under this scenario, as there are fewer bulk system benefits of adding this type of facility in the area. Instead, two in-line switches are assumed at Armitage to assist with restoration. This means that under normal operating conditions, half of Armitage TS's load would be fed radially from Parkway TS, and half from the Claireville to Brown Hill circuits. This configuration was selected to avoid a parallel path between York Energy Centre and Claireville TS, out of consideration for existing short-circuit limitations at Claireville TS.

This alternative is shown in Figure 7-6.

Figure 7-6: Sample Buttonville to Armitage Configuration



The cost of this upgrade depends on the type of transmission technology used (overhead or underground). Assuming overhead transmission is selected for the full 20 km, the estimated cost today would be approximately $90 million. If a cable is used for the 6 km, which runs adjacent to the built up areas in Markham, and overhead towers are used for the remainder, an additional $75 million would likely be added to the total corridor cost.

Aside from new transmission, some smaller system upgrades would also be required to accommodate new sectionalization requirements and other constraints. Many options are possible and should be evaluated closer to when they are needed, but the sample configuration evaluated in this study would also require:

- Two new switches at Armitage TS
- Reconductoring of 2.7 km section of P45/46 between Markham #4 MTS and Buttonville TS
- Retapping Markham #4 MTS from Parkway corridor to prevent thermal and supply security needs

These smaller system upgrades are expected to cost approximately $13-15 million based on typical unit costs. Retapping Markham #4 MTS was considered as an alternative to reconductoring a 1.1 km section of P45/46 (see Section 7.3.1). This would require building a new 1.5 km supply path to remove Markham #4 MTS from the limited P45/46 circuits, and instead provide supply from the C35/36P (Parkway) circuits. Although this was not recommended to address the medium-term P45/46 thermal needs due to greater cost and impact ($5 million compared to $2 million), this new supply path would be required in the long term if total load on the circuits running north from Parkway exceeds 600 MW (roughly four fully loaded stations). Under the sample configuration shown, Markham #4-6 MTS, Buttonville TS, and half of Armitage TS could potentially be supplied by the extended P45/46 circuits. Note that under different configurations, such as a normally closed Buttonville to Armitage section, retapping may not be required; however, other, costlier upgrades may be possible. Final configuration decisions, and associated system upgrades, would be determined closer to the actual in-service date, when other system assumptions are better known.

In addition to meeting thermal needs on the Claireville to Brown Hill circuits, this alternative would also improve restoration capability at Armitage TS under a range of possible outage scenarios.

Comparison of Transmission Alternatives

Compared to the Kleinburg to Kirby transmission option, the Buttonville to Armitage alternative would impact more land (20 km vs. ~6 km). However, the corridor for the Buttonville to Armitage alternative already exists, which may have less of a land use impact than developing a new right of way. On the other hand, the new Kleinburg to Kirby corridor could be sited adjacent to a planned 400-series highway, which may lessen the incremental land use impact. Ultimately the determination of which transmission alternative has a lower impact should be made with community input, as they are different enough to make direct comparison difficult without clear criteria.

Comparison of costs is also challenging. Although the base cost of the Kleinburg to Kirby option is higher than Buttonville to Armitage ($152 million vs. $104 million if overhead), the majority of this is due to a switching station at Kleinburg, which could also provide capacity to the nearby GTA West Region, and could provide bulk system benefits as well. In fact, some expansion of Kleinburg TS may be required regardless of the choice of York capacity solution, just to enable capacity growth in GTA West. The needs and options associated with this area will be studied in the GTA West IRRP, details of which can be found on the IESO's GTA West planning webpage. If a new switching station at Kleinburg forms part of the long-term GTA West plan, and the $110 million cost can be shared between these two areas, then the cost of the Kleinburg to Kirby solution that can is attributable to York Region would be just under $100 million, comparable to or even less than the cost of the Buttonville to Armitage alternative. A better sense of the GTA West needs, related timing, and available solutions will be available when that IRRP – currently scheduled for Q1 2021 – is complete. Selecting the Buttonville to Armitage transmission alternative could also have an impact on the cost of step-down station alternatives for Markham in the medium term, as the northern station location would become more cost-effective under some scenarios if the required transmission expansion were to be triggered in the long term regardless of the chosen location of Markham #5 MTS. More details on considerations associated with the Markham #5 MTS location are provided in Section 7.3.4.

Because of the need for greater community engagement, and due to the uncertainty associated with long-term costs, this IRRP recommends that no decision be made at this time to select a preferred solution to long-term York capacity needs. Instead, ongoing engagement should continue to inform decision-making, and updates on the status of GTA West plans, the Northwest GTA Corridor Identification Study, and long-term system capacity needs should be provided regularly to stakeholders.

7.4 The Recommended Plan

After evaluating the needs and identified options, the Working Group recommends the actions described below to address near-term needs and preserve longer term options. All longer-term recommendations are subject to further review and amendments, as system conditions change and assumptions evolve.

Collect Information on future NWAs and Opportunities in York Region to inform the next IRRP

Actual need dates for medium- and long-term needs are dependent on peak demand, which can be deferred through non-wires solutions, such as EE and DERs. Activities are currently underway to inform non-wires potential in York Region, and address some of the operational challenges associated with relying on these technologies to address transmission needs. These activities include an interoperability pilot described further in Section 7.2. The IESO is currently working with government and stakeholders to consider opportunities for EE in Ontario beyond 2020. Consideration of the deferral value of wires infrastructure, in addition to the value of avoided system energy and capacity, should be leveraged and included when determining the feasibility and cost-effectiveness of a program.

The Working Group should monitor the impacts of EE programs, as well as other initiatives in the region, such as the interoperability pilot. to inform long-term recommendations required in the next IRRP (currently anticipated for 2025 completion). Additionally, as part of ongoing engagement with municipalities and stakeholders, the IESO will actively seek new opportunities to target peak electricity demand. In particular, opportunities to defer the medium-term need for step-down station capacity and long-term need for major system capacity upgrades will be evaluated to determine feasibility and cost-effectiveness.

Actual annual peak demand growth will also continue to be monitored to better inform actual need dates, and may potentially defer or advance further study or implementation of preferred solutions.

Reconfigure York Energy Centre Station Service Supply

The station service supply for York Energy Centre may cause the station to shut off automatically following certain contingencies, triggering thermal and voltage needs on the local transmission system. At the moment, this is being addressed by arming automatic load rejection through an SPS, but this measure will no longer be sufficient to meet needs by approximately 2033. Given that advancing this work would have immediate benefits for local customer reliability, improve resource availability, and facilitate operational functions, such as outage management, the Technical Working Group recommends that the IESO and Capital Power (York Energy Centre's operator and 50% owner) proceed to identify and consider options for a new station service supply arrangement. Any new configuration should allow for continuous

York Energy Centre operation following the simultaneous loss of H82/83V (total loss of distribution supply from Holland TS) or the loss of B88H (loss of transmission supply point).

Develop Markham #5 MTS

To address the need for additional step-down station capacity in Markham, the Technical Working Group recommends development of a new step-down transformer station. Named "Markham #5 MTS", this new station is to be developed by Alectra, with a targeted in-service date of 2025. Two candidate locations (Buttonville TS and northern Markham) have been studied and were found to have similar long-term costs, assuming overhead transmission and no preferred solution to address long-term capacity needs has been identified. In the event that the Buttonville to Armitage transmission solution is identified as a preferred alternative to meet long-term capacity needs, the northern Markham location would be economically preferable. Given the uncertainty associated with choosing a preferred outcome for a system capacity need not anticipated until the early- to mid-2030s, this IRRP recommends that Alectra select a preferred location for the Markham #5 MTS based on engagement with the local community. A hand-off letter for initiating work on Markham #5 MTS was sent to Alectra by the IESO in 2017.

Reconductor Circuit P45/46 from Parkway to Markham #4 MTS

The Technical Working Group recommends that Hydro One proceed with reconductoring of a limiting circuit segment to a higher ampacity. This upgrade will enable an additional 180 MW to be served in the Markham area without exceeding thermal limits of the system. This IRRP recommends the upgrade be complete by the time the Markham #5 MTS comes into service (currently forecast for 2025), to ensure full station loading is available. Based on a high-level assessment using typical unit costs, this upgrade is expected to cost approximately $2 million.

Develop Northern York TS

Following the need for step-down station capacity in the Markham area in 2025, additional station capacity needs are anticipated in Northern York in 2027 and Vaughan in 2030. Although development work is not yet required, and dates are subject to deferral through non-wires measures, the Technical Working Group recommends that a suitable location be identified and preserved for the future Northern York station at this time. Given development pressures in the area, deferring the search may make finding a suitable location difficult or costlier. While other locations are still possible, at this time the future Northern York TS will likely be located in East

Gwillimbury, based on the area's high growth rate and lack of existing step-down stations. This IRRP recommends that Hydro One undertake a review of suitable locations to accommodate a potential in-service date as early as 2027 and that Hydro One begin development when actual peak demand and/or updated load forecasts suggest that the new Northern York TS needs to be operational within three years.

A suitable location already exists for Vaughan #5 MTS, at the site of the existing Vaughan #4 MTS. No additional work is required at this time.

Develop/Preserve Viability of Long-term Capacity Options

A long-term need for additional supply capacity to serve demand growth in York Region is currently anticipated as early as 2033, but subject to deferral. This need could be met through new large-scale dispatchable resources, or new transmission. Two viable transmission-based options have been identified. One would require the redevelopment of an existing transmission corridor (Buttonville to Armitage), while the other requires the development of a new transmission right of way (GTA West corridor, Kleinburg to Kirby section). A recommendation on the final preferred option to address these capacity needs is not required at this time, but actions should be taken today to preserve these options for when a decision is required, including continued engagement with the local community to assist in identifying a preferred option.

Additionally, ongoing work to preserve transmission rights adjacent to the proposed GTA West highway corridor should continue. Co-location of linear infrastructure is consistent with the Provincial Policy Statement and good planning practice, and should be pursued for the GTA West corridor regardless of which long-term system capacity solution is eventually selected for York Region. Long-term development of transmission along the GTA West corridor could have benefits for supply capacity in both the York and GTA West regions, and could potentially be leveraged to address future bulk system needs for the GTA as a whole.

No Additional Action Required on Specific Restoration or Supply Security Needs

Although three areas have been identified as being at risk for restoration or supply security needs over the 20-year planning horizon, no further action beyond the recommendations included above is required at this time:

1. **Kleinburg Radial Tap (V43/44).** One of the solutions to address long-term capacity needs in the area (the Kleinburg to Kirby transmission link) has the potential to address restoration needs along these circuits. Until a preferred long-term capacity solution has been selected, there is no need to pursue other potential solutions, as these costs may end up stranded.
2. **Parkway Corridor (V75/71P).** This need has been studied through the 2015 IRRP, and a recommendation has already been implemented.
3. **Northern York (B82/83V and B88/89H).** Both the identified near-term restoration need and longer-term supply security need would be addressed through the recommendation to reconfigure York Energy Centre station service supply. No further action is required.

7.4.2 Implementation of Recommended Plan

To ensure that the near-term electricity needs of York Region are addressed, and longer-term options preserved, some plan recommendations will need to be implemented soon. These specific actions and deliverables are outlined in Table 7-4, along with the recommended timing.

Table 7-4: Summary of Needs and Recommended Actions in York Region

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
Collect information on future NWAs and opportunities in York Region to inform the next IRRP	Continue to monitor progress of pilots and programs to inform potential and barriers to further non-wires implementation Actively seek new opportunities from municipalities and stakeholders to target peak electricity demand Track actual summer peak demand, net of the impact of NWAs	IESO/LDCs	Annually
Reconfigure York Energy Centre station service supply	IESO to work with Capital Power to identify and consider options for a preferred station service arrangement	IESO	Ongoing
Address the potential for high voltages on M80/81B	Hydro One to identify a preferred solution through the RIP, and implement no later than 2025	Hydro One	2025
Develop Markham #5 MTS	Design, develop and construct new station in Markham	Alectra	In service 2025
Reconductor circuit P45/46 from Parkway to Markham #4 MTS	Design, develop, and carry out reconductoring of limiting section of P45/46 in time for planned Markham #5 MTS in-service date	Hydro One	In service 2025 (unless Markham 5 deferred)
Develop Northern York TS	Identify and secure preferred location for new Northern York step-down station Hydro One to begin development as required to ensure facility is in service when needed	Hydro One	Tentatively In service 2027

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
Develop/preserve viability of long-term capacity options	Continue working to preserve transmission right adjacent to proposed GTA West highway corridor Continue to engage with community on preferred long-term supply options and considerations	IESO	Ongoing

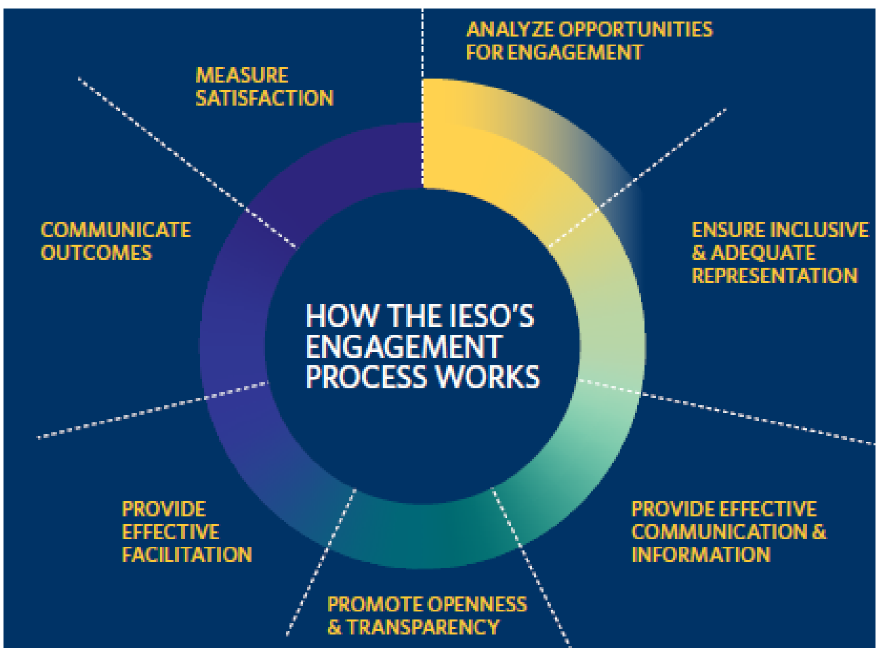
8. Community and Stakeholder Engagement

Engaging with communities and interested parties is an integral component of the regional planning process. Providing opportunities for input in regional planning enables the views and preferences of the community to be considered in the development of an IRRP and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to inform the creation of this IRRP.

8.1 Engagement Principles

The IESO's Engagement Principles[16] guide the process to help ensure that all interested parties were aware of, and could contribute to, the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, and to support its efforts to build trusted relationships.

Figure 8-1: IESO Engagement Principles



[16] http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Overview/Engagement-Principles

8.2 Creating an Engagement Approach for GTA North

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Discussions to help inform the engagement approach for the planning cycle
- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs

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

- A dedicated webpage on the IESO website
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin
- Public webinars
- Face-to-face meetings
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (See section 1.4 Outreach with Municipalities)

The IESO leveraged a dedicated engagement webpage to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process.

8.3 Engage early and often

Leveraging existing relationships built through the previous planning cycle, the IESO held preliminary discussions to help inform the engagement approach for this new round of planning. This started with an invitation to targeted communities and those with an identified interest in regional issues to learn more about how to provide comments on the GTA North Scoping Assessment Report[17] before it was finalized.

[17] The Scoping Assessment Report identified the need for an IRRP and included the terms of reference to guide the development of the plan. Following a window for comments, the final report was published in August 2018. No comments were received.

To ensure openness and transparency in the engagement process, the IESO created a dedicated webpage on the IESO site that provided information on all engagement activities, including background information, presentations, and the details and recordings of all public webinars.

The IESO also regularly provided updates through its weekly Bulletin and emails to interested stakeholders.

Three webinars were held throughout the engagement initiative to give interested parties an opportunity to hear about progress and provide input on key components of the IRRP. The topics were:

- Draft electricity demand forecast, preliminary needs and community engagement
- Defined needs and range of potential solutions to be examined
- Results of the options evaluated, draft recommendations and next steps

Webinar materials that included questions for input were provided in advance to help participants prepare to provide feedback.

The webinars were well attended participants including municipal representatives, sustainability and environment organizations, generators, energy service providers and consultants, gas companies, planning consultants and local resident associations. While interest was high, very few questions and comments were received during the written feedback windows.

8.4 Outreach with Municipalities

At milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were also held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, broader community engagement.

The IESO engaged directly with municipal staff with responsibility for planning, sustainability, asset management, energy and climate change. These meetings yielded great discussions and valuable insights in a few critical areas that are addressed in the IRRP, including:

- Drivers of growth in the northern portions of the GTA North region

- Issues and community feedback around potential solutions to address the long-term transmission supply capacity need
- Community preferences to pursue non-wires solutions to defer infrastructure investments and meet municipal climate change mitigation objectives
- Alignment of electricity planning with local planning activities particularly with respect to the York Region Municipal Comprehensive Review and subsequent municipal Official Plan updates

In addition to helping participants better understand the region's electricity needs, these meetings also strengthened relationships to enable ongoing dialogue beyond this IRRP, such as follow-up presentations to local Councils and workshop meetings with sustainability and planning staff.

8.5 Engagement Conclusions

Based on these discussions, following the publication of this IRRP, ongoing engagement will be required to monitor and inform regional characteristics for the next planning cycle when critical decisions will need to be made.

Although the anticipated growth in the region is medium- to long-term in nature and there is strong community interest in NWAs to defer electricity infrastructure, the magnitude of the growth is expected to require other solutions. Local growth, planning initiatives and energy projects will be closely monitored, and community engagement will continue through the IESO's GTA and Central Ontario Regional Electricity Network to ensure interested parties are kept informed and given opportunities to help shape the region's electricity future.

9. Conclusion

This IRRP has been developed for York Region, based on the electrical boundaries defined by the OEB's GTA North (York) planning region. The IRRP identifies electricity needs in the region over the 20-year period from 2018 to 2037, recommends a plan to address near-term needs, and lays out actions to monitor, defer, and address long- term needs.

To support the development of the near-term plan, this IRRP recommends actions to address near-term capacity needs, and identify and evaluate non-wires options to offset peak demand growth and defer the long-term need for system upgrades. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group. Wires infrastructure projects identified to address near term needs will become part of a Regional Infrastructure Plan (RIP) to be conducted by Hydro One as an outcome of this IRRP.

To support the development of a long-term plan, a number of actions have been identified to preserve long-term options, engage with the community to determine local preferences, and monitor growth in the region. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the regional planning process for York Region, and any additional measures required as a result of faster-than-anticipated load growth in the interim.

The York Region Technical Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

Appendix A: Overview of the Regional Planning Process

Demand Forecast