North & East of Sudbury: Integrated Regional Resource Plan

April 2023

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Powering Tomorrow.

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List of Acronyms

BKF	Breaker Failure
CDM	Conservation and Demand Management
DG	Distributed Generation
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTE	Long Term Emergency
LTR	Limited Time Rating
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
TS	Transformer Station

1. Introduction

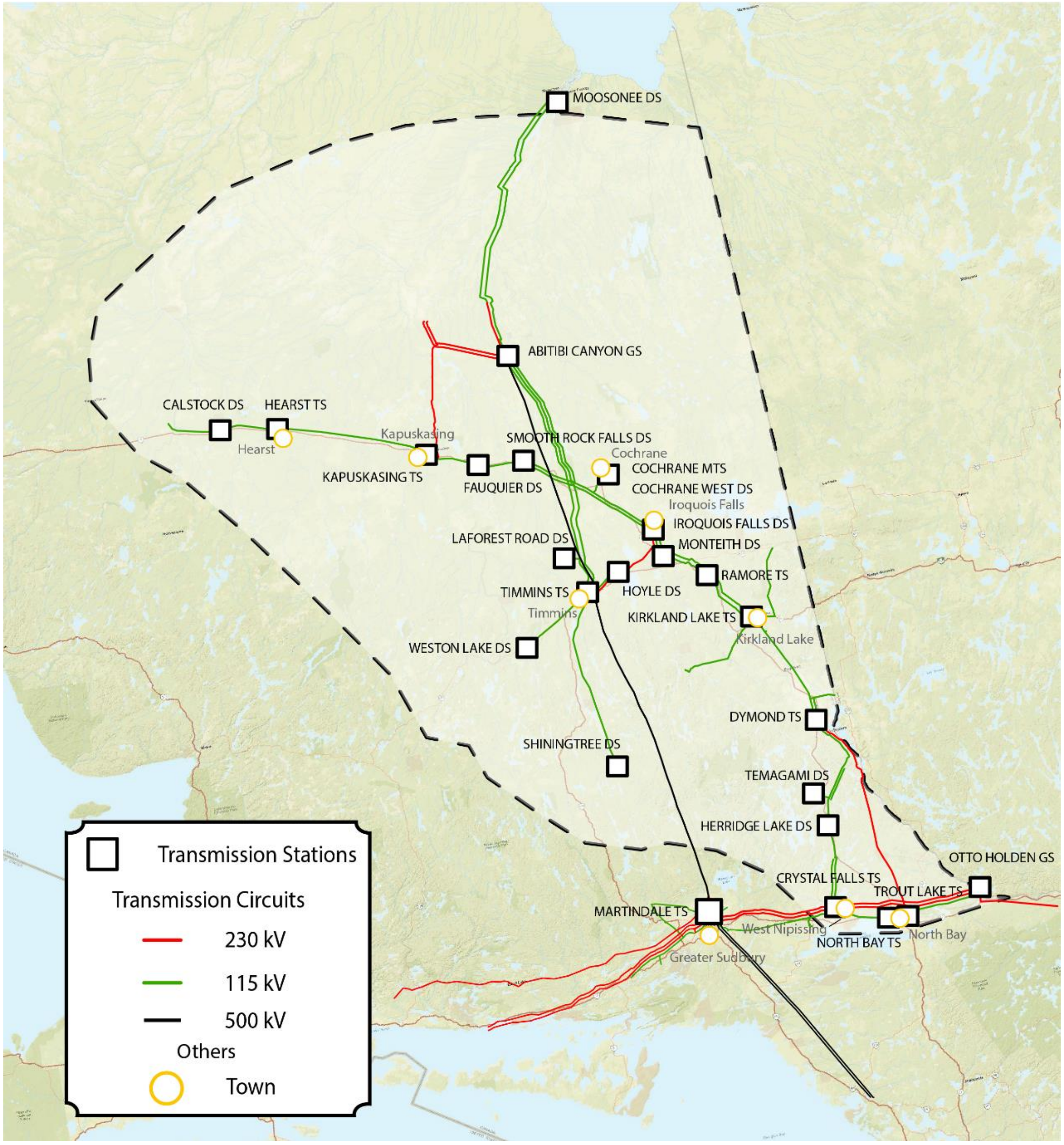
1.1 Overview of Region and Background

The North & East of Sudbury region is a large area supplied by the electricity infrastructure that extends north and east from, but not including, the City of Sudbury. Extending from south of the town of Moosonee in the north to the City of North Bay and town of East Ferris in the south, it includes the towns of Hearst, Kapuskasing, Smooth Rock Falls, Cochrane, Foleyet, Iroquois Falls, Kirkland Lake and Englehart. It also includes the townships of Black River Matheson and East Ferris, the cities of North Bay, Temiskaming Shores and Timmins and the municipality of West Nipissing. The North & East of Sudbury region is also home to First Nation communities listed in Table 1. A map of the area indicating the location of transmission assets is found in Figure 1.

Table 1 | List of First Nation Communities in the North & East of Sudbury Region

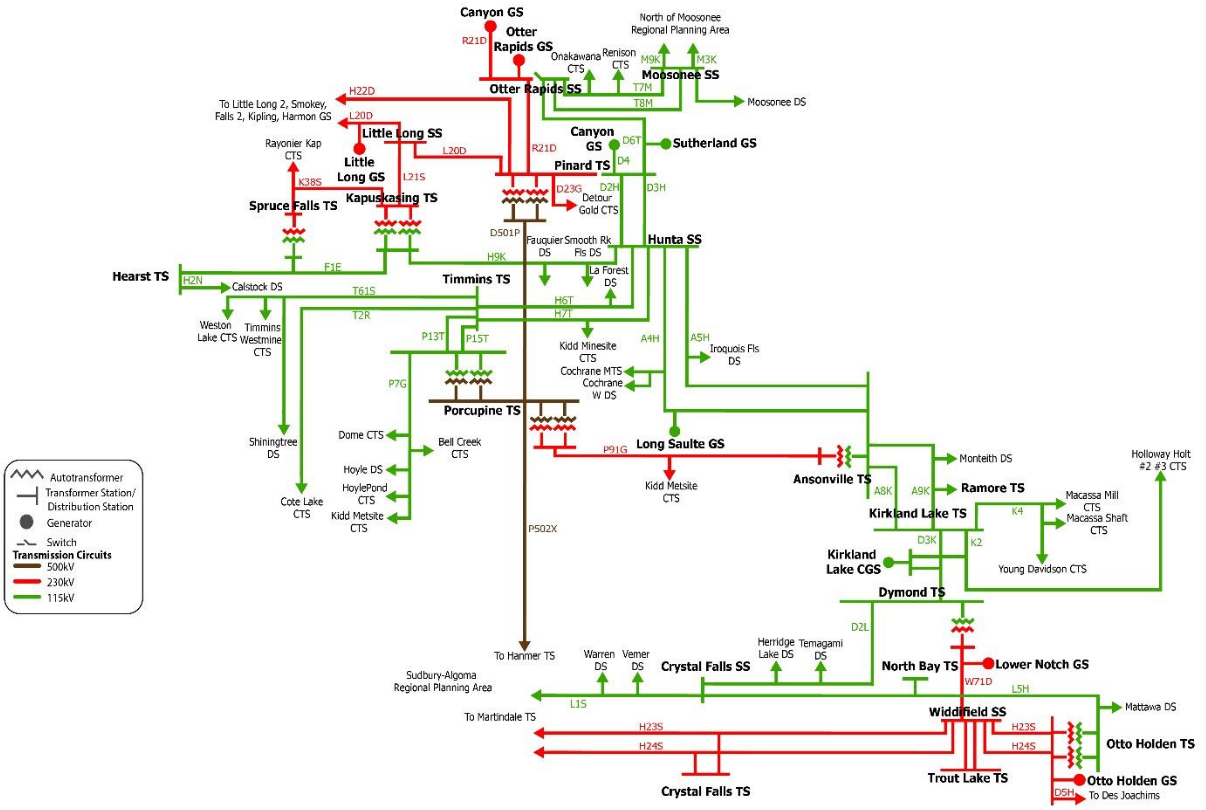
Constance Lake First Nation
Flying Post First Nation
Matachewan First Nation
Mattagami First Nation
Missanabie Cree First Nation
Moose Cree First Nation
Nipissing First Nation
Taykwa Tagamou First Nation
Temagami First Nation
Wahgoshig First Nation
Wahnapitae First Nation

Figure 1 | Map of the North & East of Sudbury Area



Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region is supplied through 500/230 kV autotransformers at Porcupine TS and Pinard TS and encompasses the 230 kV circuits east of Martindale TS in the west to Otto Holden TS in the east as well as the 500 kV circuits from Hammer TS to Pinard TS and the 115 kV sub-systems in between. For clarity, the North & East of Sudbury region does not include the area north of Moosonee. There are non-synchronous interconnections with Quebec at Dymond TS and Otto Holden TS. At Dymond TS, intertie circuit D4Z at Dymond TS can deliver imports from generation located in Quebec, and industrial load in Quebec (i.e., a paper plant in Témiscaming, Quebec) can be supplied radially via the 115 kV intertie circuit H4Z. This Quebec load is not part of this study as it can also be supplied from Quebec. A single line diagram of the electricity infrastructure in the region is shown in Figure 2.

Figure 2 | Electricity Infrastructure in the North & East of Sudbury Region



Demand in this region is winter peaking and a large share of this demand is high electricity intensity industries, primarily mining and forestry operations. Demand growth in this area is primarily forecast to be in the mining sector, where project development is highly dependent on factors such as commodity prices and access to financing.

The region has over 2,600 MW of generation, including numerous hydroelectric facilities, solar, gas and bio-fuel facilities. The lead transmitter for the region is Hydro One Networks Inc. and the local distribution companies (LDCs) are North Bay Hydro, Northern Ontario Wires Inc., Hearst Power Distribution Co., Greater Sudbury Hydro, and Hydro One Networks Inc. (Distribution).

2. The Integrated Regional Resource Plan

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

Table 2 summarizes the needs identified in this study and the IRRP's recommendations to address them.

Table 2 | Summary of Needs and Recommendations for North & East of Sudbury IRRP

No.	Need Description	Recommendation	Need Date
1	Station Capacity at Ramore TS	Load growth at Ramore TS will be monitored and revisited in the next cycle of regional planning	2033
2	Voltage control issues with existing capacitors at Dymond TS	Hydro One to investigate options to improve operability of existing capacitors in the upcoming RIP	2030
3	Voltage control issues in the Kirkland Lake area	Hydro One to investigate options of adding reactive devices in the Kirkland Lake area in the upcoming RIP	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Various recommendations, including a new RAS, replacing failed equipment and additional voltage support	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	The new Kirkland Lake RAS installed in 2022 addresses this issue. Additional load in the area beyond the current forecast will require further study	2030
6	A4H/A5H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2027

No.	Need Description	Recommendation	Need Date
7	D2H/D3H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Partially addressed by the recent Northeast Bulk Plan. An update to this plan is recommended should significant new resources and/or load connect to the North & East of Sudbury region.	Existing Need
9	Difficulty supplying loads during planned outages to circuit D501P	Study this need as part of the next bulk system plan for Northeast Ontario in combination with other drivers of system expansion as they develop	Existing Need

3. Development of the IRRP

3.1 The Regional Planning Process

In 2013, the OEB created a formal process for regional planning which is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The regional planning formal process sets out 21 electricity planning regions for the province. Regional planning assesses the interrelated needs of a region over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions to be undertaken.

The process consists of four main components:

1. A Needs Assessment, led by the lead transmitter in the region, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the most appropriate planning approach to address identified needs;
3. An IRRP, also led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A Regional Infrastructure Plan (RIP), led by the lead transmitter, which provides further details on recommended wires solutions.

Further details on the components of the regional planning process in Ontario and the IESO's approach to regional planning can be found in Appendix A.

In addition to regional planning, there are also bulk system planning and distribution network system planning processes. Bulk system planning typically considers the 230 kV and 500 kV network and examines province-wide system issues, and distribution network planning considers the adequacy and reliability of the distribution system(s) supplying customers within a particular community. Regional planning sits between bulk planning and distribution planning and focuses on ensuring that an area can be reliably supplied given forecast demand growth and other developments in a region.

A review of the regional planning process was finalized in 2021 following the completion of the first cycle of regional planning for all 21 regions. The Regional Planning Process Review Final Report is published on the IESO's website.

3.2 North & East of Sudbury and IRRP Development

The process to develop the North & East of Sudbury IRRP was initiated following the publication of Hydro One's North & East of Sudbury Needs Assessment report in May 2021 and the IESO's Scoping Assessment Outcome report in August 2021. The Scoping Assessment report recommended that the needs identified for the North & East of Sudbury region be considered through an IRRP using a coordinated regional approach. The Scoping Assessment Working Group, consisting of the IESO, the transmitter and the LDCs in the region, was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options and recommend solutions for the North & East of Sudbury region.

4. Background and Study Scope

This is the second cycle of regional planning for the North & East of Sudbury region. During the first cycle of regional planning, a Needs Assessment was conducted in April 2016 that was led by the transmitter, Hydro One Networks Inc. Transmission. After reviewing the needs identified in the report, the Technical Working Group recommended that further regional coordination was not required and a Regional Infrastructure Plan, also led by the transmitter, was published in April 2017.

This cycle of regional planning started with a Needs Assessment published by Hydro One in May 2021 which identified a number of needs requiring further regional coordination. This was followed by a Scoping Assessment process which was finalized in August 2021. The Scoping Assessment Outcome report recommended that an IRRP be initiated. This report is the outcome of the IRRP process and presents an integrated regional electricity plan for the next 20-year period from 2021 to 2040.

4.1 Study Scope

This IRRP was prepared by the IESO on behalf of the Technical Working Group and recommends options to meet the electricity needs of the North & East of Sudbury region of the study period with a focus on providing an adequate, reliable supply to support community growth. The plan includes consideration of forecast electricity demand growth, conservation and demand management (CDM), distributed generation (DG), transmission and distribution system capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system. The full scope of the study can be found in Appendix D.

4.1.1 Planned Projects Considered in the IRRP

The following projects were already planned or underway when the IRRP was initiated, and were assumed to be in service in developing the IRRP assumptions.

1. Ansonville to Kirkland Lake Line Upgrade: Upgrading of end-of-life circuits A8K and A9K from 230 A to 550 A capacity.
2. Kapuskasing Area Reinforcement: Upgrading two sections of circuit H9K (from Spruce Falls JCT to Carmichael Falls JCT and Gemini Smooth Rock Falls JCT to H9K Structure 127A JCT) to higher 550 A capacity.

The North & East of Sudbury IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast;
- Examining the capacity and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC planning criteria, and considered the findings and recommendations made through other planning processes being carried out in parallel, namely the Northeast Bulk Plan;
- 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 wires alternatives (e.g., transmission and/or distribution) and non-wires alternatives (e.g., energy efficiency, local generation, storage and other distributed energy resources);
- Engaging with the community on needs, findings and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions and recommendation within a detailed plan.

4.2 Coordination with Bulk Planning Initiatives

In addition to the Regional Planning activities being undertaking for the North & East of Sudbury region, a number of Bulk Planning initiatives have recently been undertaken or are currently underway with the potential to affect assumptions and outcomes in the area. Two initiatives in particular, the Northeast Bulk Plan, and the Northern Voltage Study, have implications for the current Regional Planning process, with further details described below.

4.2.1 Northeast Bulk Planning Study

A bulk planning study was initiated for northeastern Ontario in 2021 that was completed in October 2022. This study examined a number of needs in the area, and paid particular focus to improving supply security for growing demand in and around the cities of Sault Ste. Marie and Timmins. Compared to a regional planning focus, the goal of the bulk study was to ensure sufficient power could be delivered to load centres, but did not include final customer delivery, including step down or local voltage needs.

Recommendations made during this study were treated as input assumptions for the current North & East of Sudbury IRRP, and were assumed to come into service at their target date. The Northeast Bulk Plan recommended the following system reinforcements.

1. A new ~260 km single circuit 230 kV transmission line (built to 500 kV standards) between Wawa Transformer Station (TS) and Porcupine TS to be in-service in 2030;
2. A new ~205 km single circuit 500 kV transmission line between Mississagi TS and Hanmer TS and addition of two new autotransformers at Mississagi TS to be in-service in 2029; and
3. A new ~75 km double circuit 230 kV transmission line between Mississagi TS and Third Line TS to be in-service in 2029.

Additional information on this study is available on the IESO website, here.

4.2.2 Northern Voltage Study

The Northern Voltage Study was initiated recognizing that the voltage profile across northern Ontario was set to change with system expansions planned in northeast Ontario (i.e., the Northeast Bulk Plan recommendations) as well as in northwestern Ontario (i.e., the East West Tie expansion, the Waasigan line and the Wataynikaneyap line). The study examines reactive requirements associated with these new lines and the resulting changes to the voltage profile. In addition, it addresses existing challenges managing system voltages in northern Ontario as reported by the IESO's control room operators and identifies requirements to improve operability.

Although the scope of the Northern Voltage study is much wider than the North & East of Sudbury IRRP, and tends to focus on contingencies and operational concerns outside the typical scope of Regional Planning, the potential for needs and recommended solutions from one study to affect system assumptions for the other required that these two studies be carried out in a coordinated manner. Since bulk system reactive requirements were being studied through the Northern Voltage Study, the North & East of Sudbury IRRP did not address these issues and instead focused on identifying and addressing localized voltage concerns in the region.

5. Electricity Demand Forecast

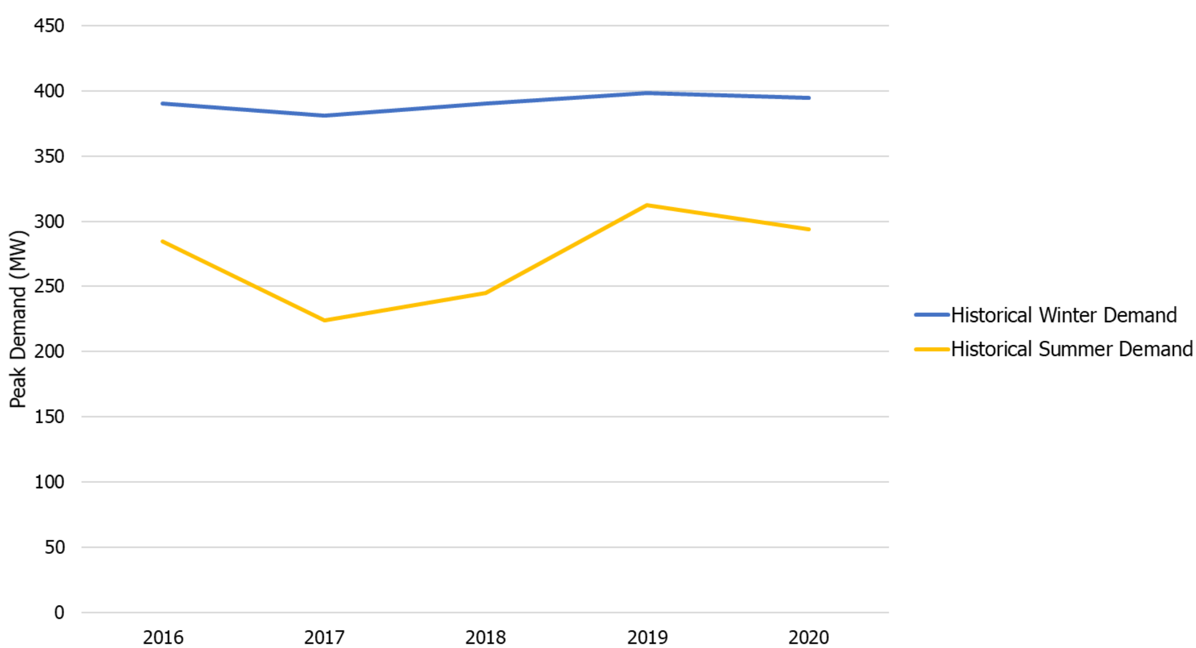
Regional planning is driven in large part by the need to meet peak electricity demand requirements in the region under study. This section describes the specific details of the development of the demand forecast for the North & East of Sudbury region, which is comprised of an LDC demand forecast as well as a forecast of transmission-connected loads (i.e., large industrial customers). It highlights the assumptions made for peak demand forecasts including the contribution of CDM and distributed generation to reducing peak demand. The resulting net demand forecast, termed the planning forecast, is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the North & East of Sudbury region, the peak loading hour for each year occurs in the winter season.

5.1 Historical LDC Electricity Demand

Historical LDC electricity demand in the North & East of Sudbury region is primarily driven by residential and commercial customers (with the exception of Ramore TS and North Bay TS which are largely industrial driven) and demand typically peaks during the winter months. Winter demand is also typically much higher than summer demand as seen in Figure 3 below.

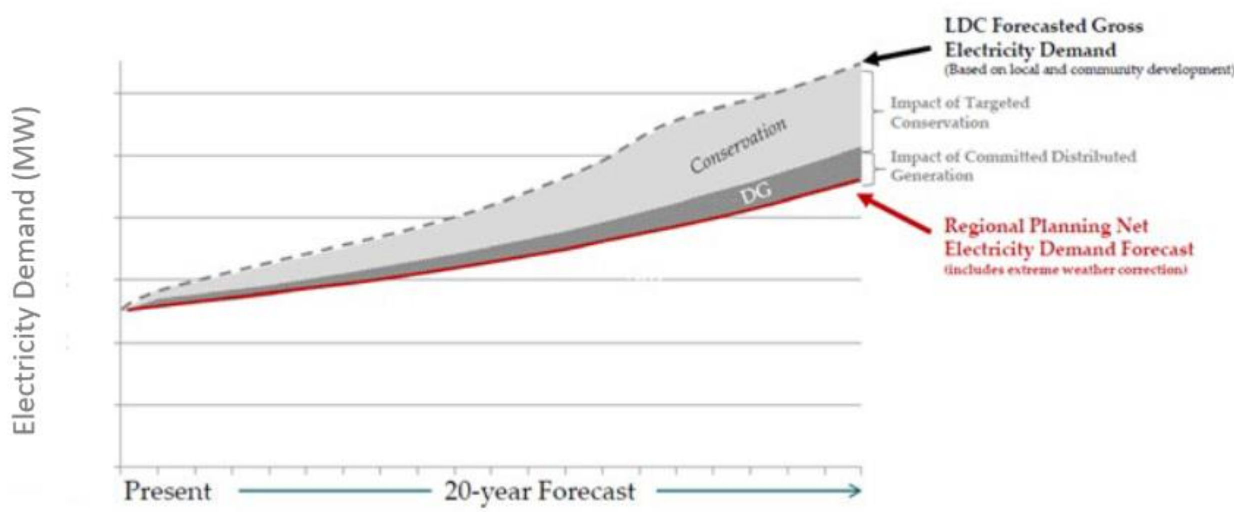
Figure 3 | Historical LDC Winter and Summer Peak Demand for the North & East of Sudbury Region



5.2 LDC Demand Forecast Methodology

A 20-year regional peak demand forecast was developed to assess reliability needs for the North & East of Sudbury sub-region; Figure 4 shows the steps taken to develop this. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions i.e., normal weather, were provided by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation savings and DG contracted through previous provincial programs such as FIT and microFIT. The forecasts were then adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments to assess the electricity needs in the region. An illustrative example is provided in Figure 4. Additional details related to the development of the demand forecast are provided in Appendix B.

Figure 4 | Illustrative Development of the Demand Forecast



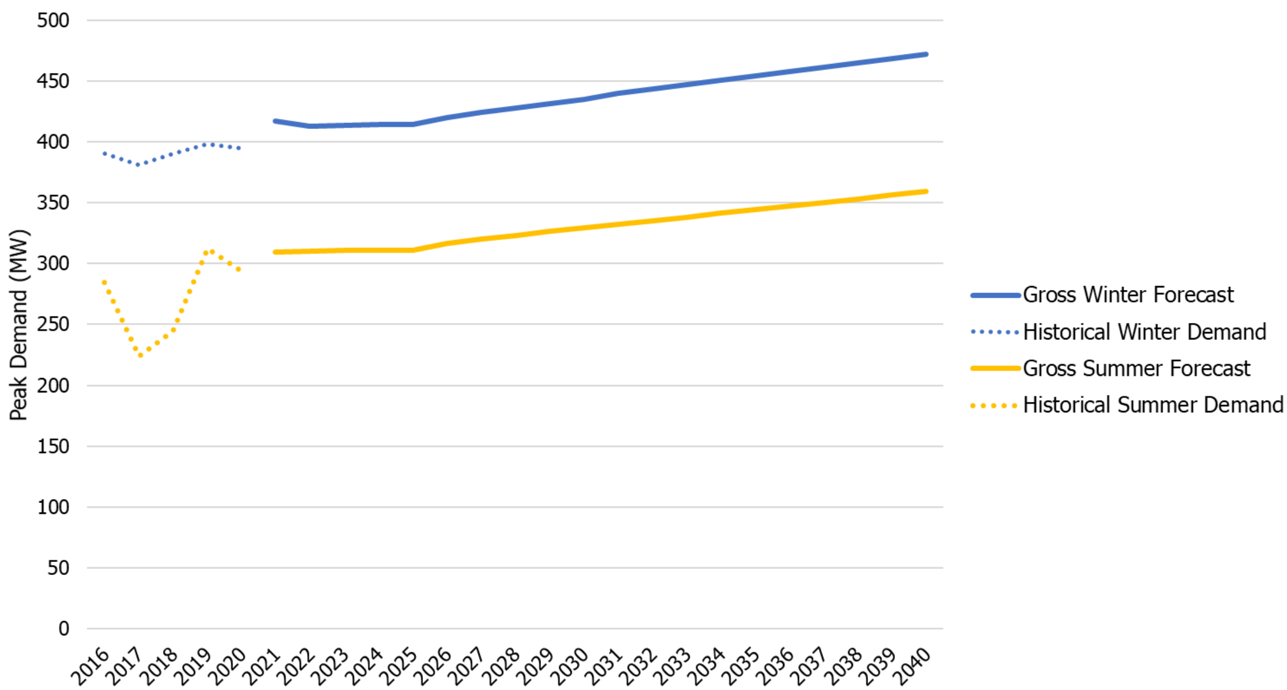
5.3 LDC Gross Demand Forecast

Gross demand forecasts were submitted by each participating LDC in the North & East of Sudbury region. LDCs have knowledgeable insights into future local demand growth and drivers due to their direct involvement with their customers. These insights include future connection applications and knowledge of typical electrical demand trends for different types of customer groups.

The LDC gross demand forecasts account for increases in demand due to factors such as new or intensified development, economic growth, population growth, changes in consumer behaviour. Most LDC's cited alignment with municipalities and credited them as a primary source for input data. LDCs are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future DG or new conservation measures, such as codes and standards and CDM programs, which are accounted for by the IESO as discussed in Section 5.4 below. The gross LDC forecast assumes median on-peak weather conditions.

More details on the individual LDCs' load forecast methodology can be found in Appendix B. Figure 5 below shows the total gross coincident LDC forecast for both summer and winter demand.

Figure 5 | Gross Winter and Summer LDC Forecast for the North & East of Sudbury Region



5.3.1 Contribution of Conservation to the LDC Demand Forecast

Conservation and demand management is a clean and cost-effective resource that helps meet Ontario's electricity needs and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

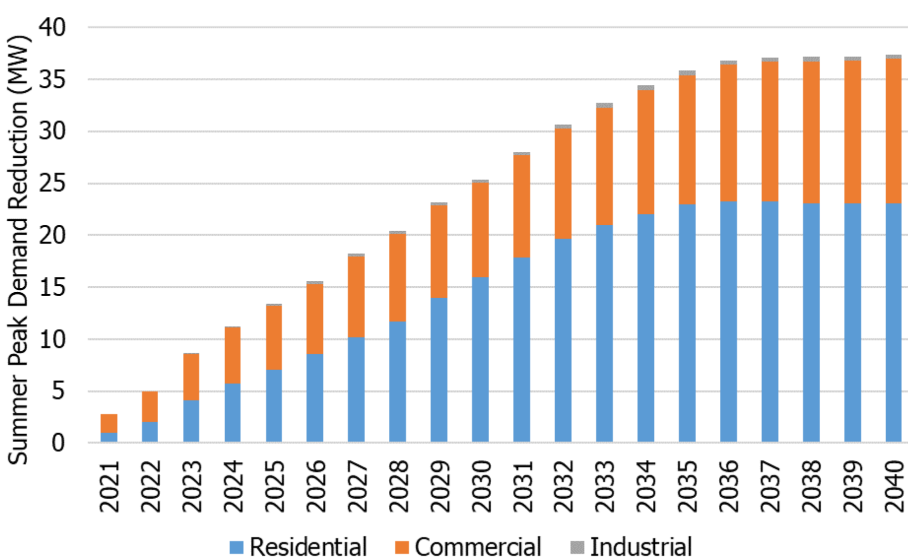
The estimate of demand reduction due to codes and standards is based on expected improvement in the codes for new and renovated buildings and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e. residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the provincial 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and assumptions regarding continuing provincial CDM programming after 2024.

CDM savings have been applied to the North & East of Sudbury region's LDC gross peak demand forecast for median weather, along with DG (as described in Section 5.3.2) to determine the net peak demand for the region. This takes into account both conservation through the provincial CDM Framework, as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast.

Figure 6 shows the estimated total yearly reduction to the LDC demand forecast due to conservation from codes, standards and CDM programs for each of the residential, commercial and industrial consumers. Additional details are provided in Appendix B.3.1.

Figure 6 | Estimated total yearly reduction to the LDC demand forecast due to conservation



5.3.2 Contribution of Distributed Generation to LDC Demand Forecast

The effect of Distributed Generation (DG) in offsetting demand is also factored in to the North & East of Sudbury region gross peak demand forecast for median weather. No assumptions were made regarding DG growth as in the long term, as the contribution of DG is expected to diminish as contracts expire. The resources that were included in the DG forecast were comprised of solar and hydroelectric projects. Specific capacity contribution factors were attributed to each resource type in order to estimate the effective capacity that would be available to shave load during the regional peak hours. Upon applying the associated capacity contribution factors to each resource in the DG list, the data was then aggregated on a station level in order to put together a forecast specifying the estimated peak load reduction due to DG output.

The following load supply stations included in this IRRP have embedded DG resources:

- Crystal Falls TS
- Kapuskasing TS
- Ramore TS
- Timmins TS
- Dymond TS
- Trout Lake TS

The effective winter capacity of DG across the region totaled 16 MW in 2022. The expected annual peak demand contribution of contracted DG in the North & East of Sudbury region and capacity contribution factors can be found in Appendix B.

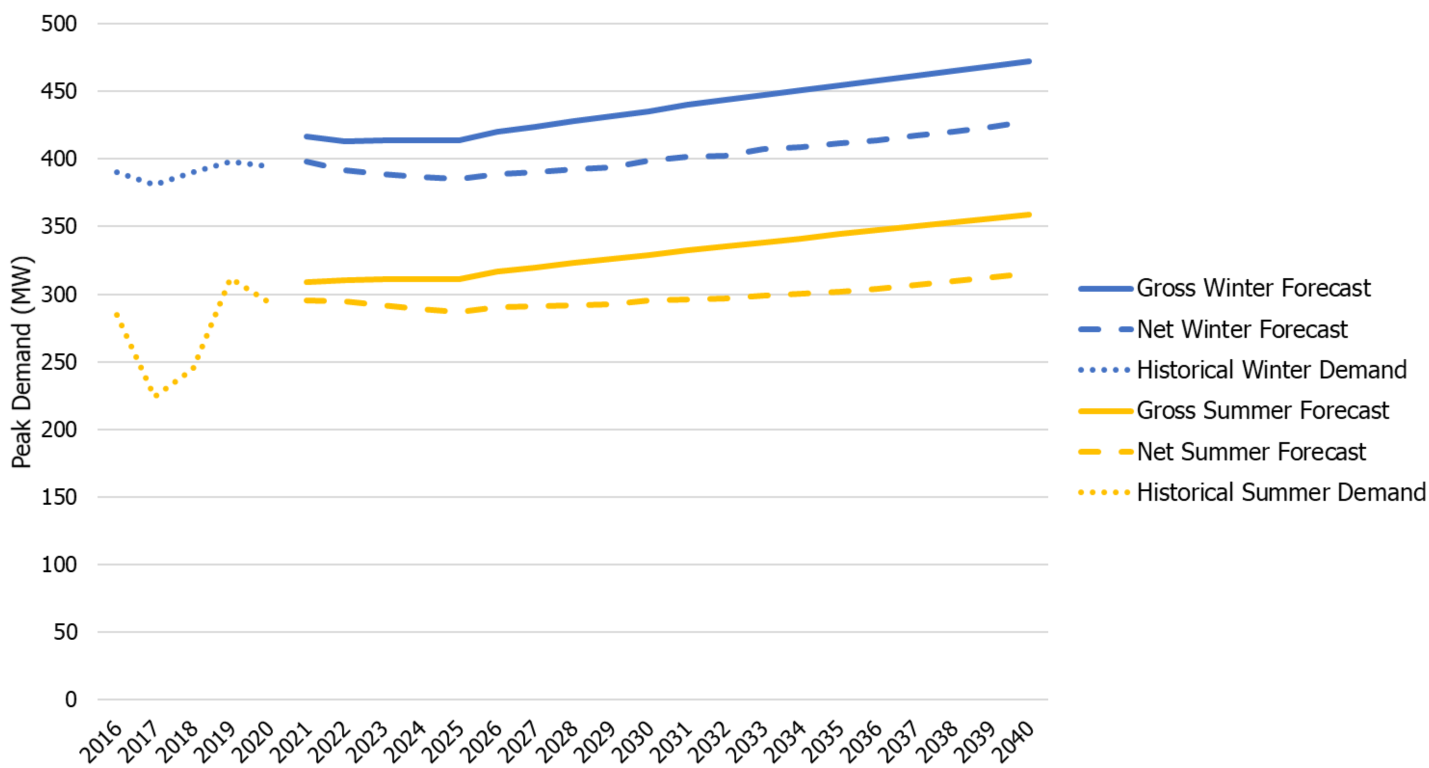
5.3.3 LDC Net Extreme Weather Planning Forecast

The net extreme weather planning forecast, also known as the "planning" forecast, is the coincident peak demand forecast for the region and is used to carry out system studies for identifying potential needs in the North & East of Sudbury region. This forecast is created in three steps:

1. The gross median weather forecast, provided by the LDCs, is adjusted to extreme weather conditions, according to the methodology described in Appendix B. The result is a gross extreme weather forecast.
2. The impacts of forecast CDM savings and DG output are subtracted from the gross extreme weather forecast to produce a net extreme weather forecast, or planning forecast.
3. A coincidence factor is applied to the forecast at each station to create a non-coincident forecast. The coincidence factor is based on the contribution of each station to the region's coincident peak over the past five years. Non-coincident station forecasts are utilized for assessing the capacity adequacy of each transformer station in the region.

The gross and net extreme weather coincident forecasts for the North & East of Sudbury region are shown in Figure 7 below for summer and winter.

Figure 7 | Extreme Weather Gross and Net Winter and Summer LDC Forecasts for the North & East of Sudbury Region



5.4 Transmission-Connected Forecast

Forecast demand growth among transmission-connected customers in the North & East of Sudbury area primarily consists of new or expanded mining projects and associated industrial processes (e.g. refining). The transmission-connected forecast represents the most up to date information on the timing, size and likelihood of these mining customers either increasing their existing demand or connecting to the system as a new customer.

The mining forecast is project-based and built from the bottom up based on known mining exploration or projects collected from proponents, industry publications, utility companies, and government. Each project is assigned one of four "likelihood" factors ranging from "most likely" to "least likely" that represents the probability of its electricity demand materializing to enable the creation of scenarios that represent different potential future outcomes.

A project's likelihood is informed by factors such as the reliability of available data sources, development stage of the project, project timing, and permitting information. The IESO also incorporates input from the Ministry of Mines on the forecast and likelihood factors. The mining forecast scenarios are summarized in Table 3 below.

Table 3 | Mining Forecast Scenario Descriptions

Scenario	Description
Low	- Conservative scenario including only existing mining projects and their extension/expansion/retirement plans - The full demand forecast for all existing mining projects is included

Reference	- Includes all demand in the low scenario plus demand forecast from projects classified as "most likely" and "likely" discounted according to their likelihood classification:
	    o "Most likely" project forecasts are not discounted
	    o "Likely" project forecasts discounted to 80% of their full project demand
	- Aligned with 2021 Annual Planning Outlook[1] reference scenario

High	- Includes all known mining projects with each project's demand forecast discounted according to their likelihood classification:
	    o "Most likely" project forecasts are not discounted
	    o "Likely" project forecasts discounted to 80% of their full project demand
	    o "Less likely" project forecasts discounted to 50% of their full project demand
	    o "Least likely" project forecasts discounted to 20% of their full project demand
	- Aligned with 2021 Annual Planning Outlook high scenario

The transmission-connected forecast for the North & East of Sudbury area is comparable in size to the LDC forecast. However, transmission-connected customers tend to have a more noticeable impact on the transmission system as they tend to have a flat demand profile (i.e., 24/7 operation) and are large loads. Large step increases in demand from new or expanded transmission-connected customers can stress the system more quickly than growth in LDC load which tends to have a more predictable and slower growth rate as seen in Figure 7 above. Therefore, these transmission-connected customers are more likely to drive system enhancements to support their growth/new connections. The transmission-connected forecast is shown in Figure 8 below.

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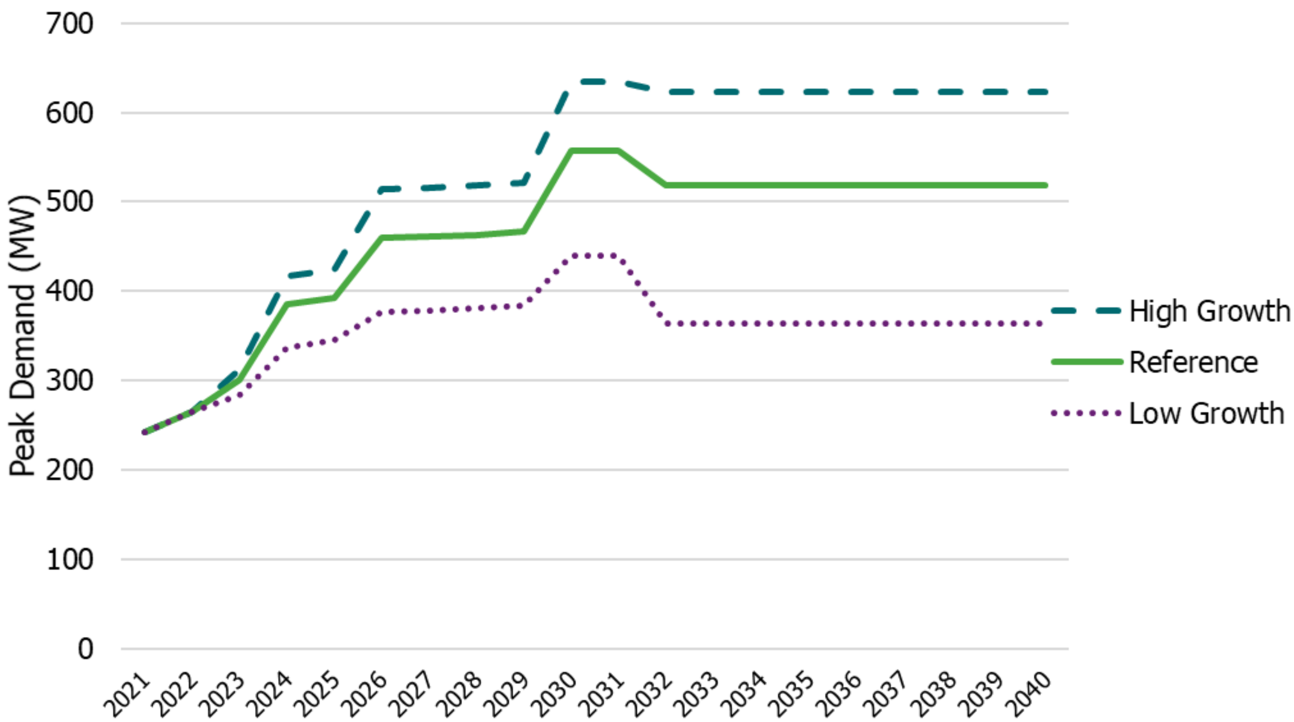
[1] The Annual Planning Outlook forecasts electricity demand, assesses the reliability of the electricity system, identifies capacity and energy needs, and explores the province's ability to meet them. The latest Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

Figure 8 | Transmission-Connected Forecast



5.5 Load Profiling

In addition to the annual peak demand forecast, hourly load profiles (8,760 hours per year over a 20 year forecast horizon) for a station with an identified capacity need were developed to characterize these needs with finer granularity. The profiles are based on historical data adjusted for variables that impact demand such as calendar day (e.g. holidays and weekends) and weather impacts (e.g. extreme weather events like ice storms or heat waves). The profiles are then scaled to match the annual peak demand forecast for each year. These profiles are used to quantify the magnitude, frequency and duration of needs to better evaluate the suitability of non-wires alternatives options.

Additional load profile details including summary tables and hourly heat maps for each need (where appropriate) can be found in Section 6.2.1.1 and Appendix B.

6. Electricity System Needs

6.1 Needs Assessment Methodology

Based on the net extreme weather planning demand forecast, the transmission-connected forecast, the transmitter's identified end-of-life asset replacement plans, and the application of ORTAC planning criteria and North American Electric Reliability Corporation (NERC) TPL-001-4 Standard, the Working Group identified electricity needs for the following categories:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day LTR of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be limited when downstream or upstream equipment, e.g., breakers, disconnect switches, low-voltage bus or high voltage circuits, is undersized relative to the transformer rating.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area at peak demand. This is limited by the load meeting capability (LMC) of the transmission supply to an area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission elements, e.g., a transmission line, group of lines, or autotransformer, when subjected to contingencies and criteria prescribed by ORTAC and TPL-001-4. LMC studies are conducted using power system simulation analysis. An area's LMC can be limited by the thermal ratings of the equipment, or the voltage levels/changes following a contingency in the area.
- **End-of-life Asset Refurbishment Needs** describe the needs identified by the transmitter with consideration to a variety of factors such as asset age, the asset's expected service life, risk associated with the failure of the asset and its condition. Replacement needs identified in the near-and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium-to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

In addition, for the North & East of Sudbury IRRP, several existing operational needs were identified through discussion with the IESO's control room operators and outage planning staff. These needs include localized voltage control issues and difficulty planning 500 kV outages while still maintaining supply to customers in the area.

Technical study results can be found in Appendix D. The needs identified in this IRRP are discussed in the section below.

6.2 Needs Identified

Table 4 below summarizes the needs identified by the North & East of Sudbury IRRP. Some needs previously identified (e.g. Kirkland Lake TS capacity need in 2040, higher than standard operating voltages in the Porcupine to Hunta area) were deferred to the next round of regional planning. For Kirkland Lake TS, the uncertainty regarding certain mining loads and the long term nature of the need means that the need could be deferred. The high operating voltages from Porcupine to Hunta requires more coordination and discussion with existing customers whose equipment are designed to operate at these high voltages. Furthermore, the North of Moosonee region will need to be studied to see if lower operating voltages can be accommodated. Such an activity is outside the scope of this regional plan and is suggested to be addressed in the North of Moosonee regional planning process.

Table 4 | Summary of Needs for North & East of Sudbury IRRP

No.	Need Description	Need Date
1	Station Capacity at Ramore TS	2033
2	Voltage control issues with existing capacitors at Dymond TS	2030
3	Voltage control issues in the Kirkland Lake area	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	2030
6	A4H/A5H End-of-Life Need	2027
7	D2H/D3H End-of-Life Need	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Existing Need
9	Difficulty supplying loads during planned outages to circuit D501P	Existing Need

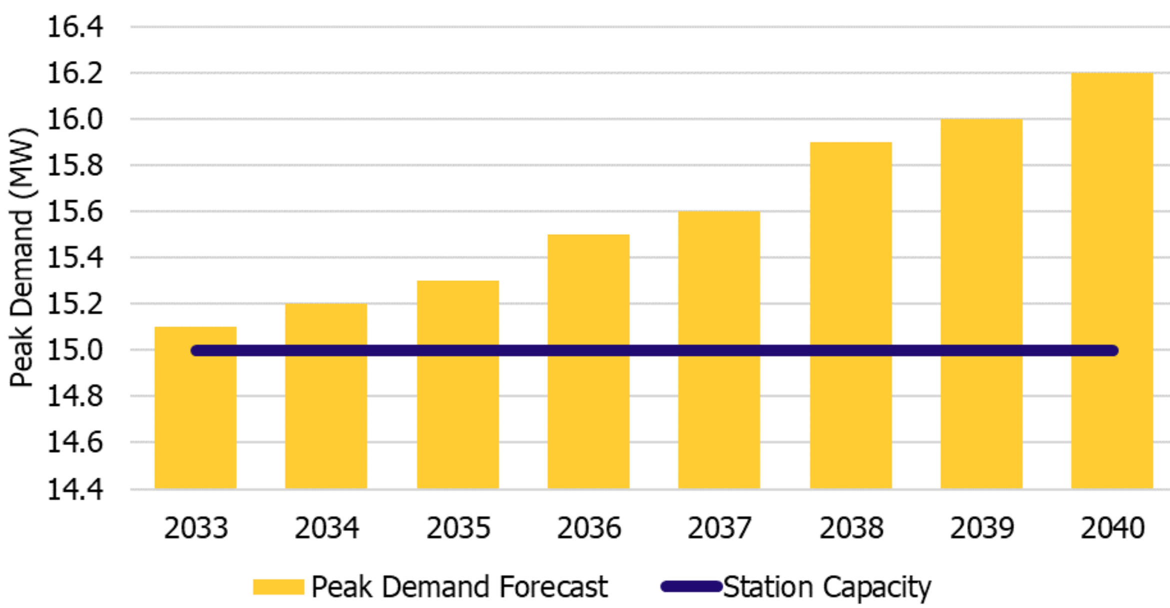
6.2.1 Station Capacity Needs

6.2.1.1 Ramore TS

Winter peak demand growth at Ramore TS is expected to exceed the station's capacity in 2033. The non-coincident winter peak forecast for Ramore TS is found in Figure 9 below.

Note that load growth in the Ramore TS service area is expected to be primarily driven by new or expanding industrial customers. These types of loads are inherently more difficult to forecast beyond the near term as growth tends to occur in large blocks if/when economic conditions support investment. As a result, the timelines associated with this need are understood to be beyond the near term (when actual applications for connection would already be known), but may be triggered with relatively short lead time thereafter. Potential options to address this need should be evaluated to ensure any necessary upgrades can be triggered with minimal planning lead time when required, as opposed to working towards a firm anticipated in-service date of 2033.

Figure 9 | Ramore TS Winter Peak Forecast



6.2.2 Supply Capacity Needs

6.2.2.1 Dymond TS Voltage Control

IESO control room operators report existing operational issues associated with the two existing capacitors at Dymond TS. They observe that the two capacitors at Dymond TS cannot be placed into service without exceeded the maximum voltage allowed by IESO Market Rules, an indication that they are too large for the area under current system conditions.[2] They also note that the existing Dymond capacitor switching scheme is a manual scheme with no telemetered status to either the IESO's or Hydro One's control rooms. This means that staff must be called out to the station to confirm or update the status of the scheme, and this can cause delays in responding to outages.

System studies show that a failure of the AL3 breaker at Dymond TS to open when called upon to clear a fault can cause voltage decline at Dymond TS, beginning in 2030. Voltage decline usually occurs when there is a large amount of load and/or lack of available reactive power resources (e.g. shunt capacitors) to provide voltage support. There are currently capacitors at Dymond TS that may address this issue. However, operators have found the current capacitors are too large to use to prevent this voltage depression.

6.2.2.2 Kirkland Lake Area Voltage Control

IESO system operators report difficulties maintaining minimum operating voltages in the Kirkland Lake area under outage conditions with recent demand growth and changes to the operation of local gas generation. System studies confirm that concurrent outages to the Kirkland Lake SVC and all units at the Northland Power Kirkland Lake Generating Station cause voltage decline issues in the Kirkland Lake area. Specifically, minimum voltages cannot be maintained at the end of the radial K2 circuit.

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[2] It is likely that when these capacitors were designed, they were sized appropriately for the area but changing system conditions over time have led to them being oversized.

6.2.2.3 Ansonville, Hunta, Kapuskasing Area Voltage Control

There are post contingency voltage control issues at Ansonville TS, Kapuskasing TS and Hunta TS for the loss of Ansonville T2 and Canyon Units.

6.2.2.4 D3K Thermal Overload

D3K is a 115 kV circuit that supplies Kirkland Lake TS from the south. Kirkland Lake TS is also supplied from the north by two 115 kV circuits, A8K and A9K. Upon the loss of either A8K or A9K when its companion is on outage, Kirkland Lake is supplied radially from the south via D3K. With forecast demand growth in the area, this outage condition will cause D3K to be thermally overloaded (102% of LTE) beginning in 2030.

6.2.3 End-of-Life Refurbishment Needs

6.2.3.1 A4H/A5H End-of-Life

Conductors on sections of A4H and A5H, namely the 25 km sections from Tunis JCT to Fournier JCT, are reaching end-of-life and are planned for replacement in 2027. This IRRP investigated whether there are other needs in the region for which there is an opportunity to right-size the ampacity of the conductors.

6.2.3.2 D2H/D3H End-of-Life

Conductors on sections of D2H and D3H, namely the 90 km sections of these circuits from Pinard TS to Hunta SS, are reaching end-of-life and are planned for replacement in 2026. This IRRP investigated whether are other needs in the region for which there is an opportunity to right-size the ampacity of the conductors.

6.2.4 Load Security and Restoration Needs

6.2.4.1 500 kV Load Security

The North & East of Sudbury region is supplied by two 500 kV circuits, P502X from Hanmer TS to Porcupine TS and D501P from Porcupine TS to Pinard TS, that are operated in parallel with a relatively weak 115 kV system. The system was developed not only to supply loads in the region, but also to integrate a substantial amount of hydroelectric generation on the Moose River which, when generating at full output result in substantial southbound flows on the 500 kV system. The need to respect the loss of either of these 500 kV circuits significantly limits the capability of this system because the 115 kV path cannot handle the post-contingency flows that would result when the 500 kV system is loaded to capacity. To address this, the system was designed around a Remedial Action Scheme (RAS), the Northeast Load and Generation Rejection Scheme (the "Northeast LGR") that enables full use of the system pre-contingency, while protecting it post-contingency by arming generation, loads, or the cross-tripping of circuits (which may also reject generation or loads by configuration) for the loss of the 500 kV path. This is a legacy system that does not meet today's planning criteria. For example, ORTAC planning criteria do not permit the use of load rejection following the loss of a single transmission element. However, bringing it up to current standards would involve substantial capital investment that is difficult to justify without the introduction of new needs (e.g., additional demand growth or resource development that would outstrip the system's current capability).

Nonetheless, the IESO recognizes customer reliability concerns and the need to work toward bringing this system up to current standards over time through its bulk and regional planning processes. The recent Northeast Bulk Plan recommendation to add a new single-circuit 500 kV line (operated at 230 kV) between Porcupine TS and Wawa TS, is a first step toward reducing reliance on load rejection in the North & East of Sudbury area. This new line is expected to reduce the frequency and amount of load rejection arming needed to respect the loss of P502X as it provides another supply point into Porcupine TS. This will, however, not address reliability concerns following the loss of D501P, which supplies the most northeastern portions of the system.

6.2.4.2 Difficulty supplying loads during planned outages to circuit D501P

IESO's outage planning staff have also identified that during recent outages to D501P, it has not been possible to supply all customer load in the area due to limitations on the 115 kV system, and certain industrial customers have been forced to reduce their production. These concerns have also been raised by these customers themselves. During D501P outages, generation must also be significantly curtailed, which can remove substantial capacity from the Ontario system.

6.2.4.3 Load Restoration Needs

No load restoration needs were identified in this IRRP.

7. Plan Options and Recommendations

In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

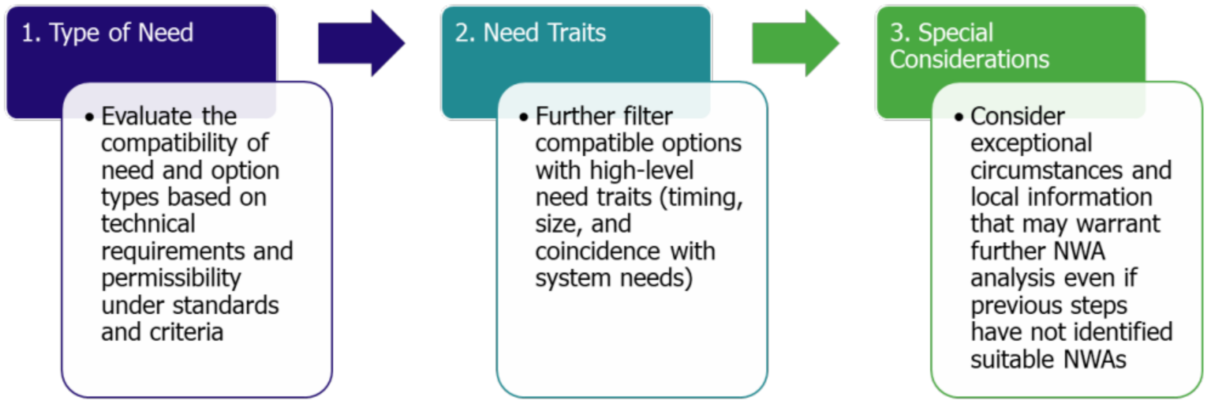
Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

1. Build new infrastructure to increase the load meeting capability of the area. These are commonly referred to as "wires" options and can include recommendations such as new transmission lines, autotransformers, step-down transformer stations, voltage control devices or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
2. Install or implement measures to reduce the net peak demand to maintain loading within the system's existing load meeting capability. These are commonly referred to as "non-wires" alternatives and can include recommendations such as local generation, distributed energy resources, or conservation and demand management.

The IESO utilized a screening approach for assessing which needs would be best suited to undergoing a detailed assessment for non-wires alternatives, including CDM. The initial screening exercise examined the duration, frequency, timing, and magnitude of the need, as well as cost of traditional wires solutions, for each identified need. Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed NWA analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 10.

The screening process resulted in NWA being considered for the station capacity need at Ramore TS. NWAs were found to not be suitable for end-of-life and voltage control needs. A like-for-standard sustainment plan is appropriate for the end-of-life needs given that the system studies did not identify any regional needs related to these assets. Needs characterization was completed for the Ramore TS station capacity need.

Figure 10 | IRRP Options Screening Mechanism



7.1 Options and Recommendations for Meeting Near- and Medium-Term Needs

7.1.1 Ramore TS Station Capacity Need

Options to address station capacity needs can be broadly sorted into two categories:

1. Keep peak loading below existing capacity, using measures such as conservation or distributed energy resources ("Non-wires alternatives), or;
2. Upgrade the station to enable additional capacity (conventional, or "Wires" solution)

Often the two categories can be considered together, with measures to offset peak demand relied upon until no longer feasible or cost effective, at which point an infrastructure upgrade becomes preferred. This type of approach can be preferable if peak capacity is expected to only marginally exceed ratings for the first few years (common in areas with relatively slower load growth), if there is insufficient lead time to accommodate a station upgrade before the need is triggered, or if uncertainty exists in the demand forecast, meaning a capacity upgrade could be "stranded" if the need never materializes. In the case of Ramore TS, there is significant uncertainty in the actual need date due to the high proportion of industrial load at the station, plus under the existing forecast assumptions, load will be only marginally above existing capacity within the study horizon. For both of these reasons, Ramore TS is considered to be a good candidate to consider non-wires measures to keep loading below existing capacity, and consider a station upgrade if and when required. Two non-wires options in particular may be beneficial for this need.

7.1.1.1 Conservation/Energy Efficiency

Conservation (or energy efficiency) involves the use of incentive programs to reduce electricity demand by upgrading/replacing existing equipment with more energy efficient alternatives. In Ontario, the IESO is currently delivering a suite of province-wide programs under the 2021-2024 Conservation and Demand Management Framework. The framework is designed to produce energy savings and offset system peak demand (which occurs in the summer). A component of this framework is the Local Initiatives Programs, which enables the IESO to pursue additional conservation in specific areas to address local electricity system needs while also contributing to meeting provincial system needs.

Given the size and timing of the need, the inherent difficulties of predicting blocky industrial load, and the misalignment with current (summer) system peak, it is recommended to defer a review and decision on targeting conservation as a solution to the Ramore TS need until the next IRRP cycle.

7.1.1.2 Distributed Energy Resources

In order to assess the appropriate DER option, a load duration forecast was created for Ramore TS. This duration forecast consists of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are studied to determine the feasibility of using DERs to address the region's needs and determine which type of DERs may be best suited to meet the needs.

Based on the profiles generated for Ramore TS, it was determined that a battery storage solution would be the best fit for the need. The battery storage solution would have a capacity of 1.2 MW and would be able to provide energy for up to six hours. The estimated cost of this battery storage solution is $3 to $3.7 million.

Given that the anticipated need for Ramore TS capacity upgrade is still several years out, it is not recommended that a non-wires alternative be developed at this time. Instead these options should be considered as potential deferral strategies and would be best pursued when actual demand and/or connection requests suggest a capacity need within the next 2-3 years. If these options prove to be insufficient to meet demand, or costlier than a wires alternative, then development work should be initiated to upgrade the station.

7.1.1.3 Station Upgrade

Ramore TS is current made up of a single 10/17 transformer, with a winter LTR of 15 MW. Hydro One has indicated that the station could be upgraded by adding a second, equally sized transformer. This type of upgrade would be expected to cost around $10-$15 million, and can be implemented with about three years' lead time.

Table 5 below shows a comparison of these alternatives, their potential capacity impact, and estimated cost. Note that due to the lead time expected before this work would be triggered, all cost and timing estimates should be considered preliminary, as they will need to be updated closer to when the work is undertaken.

Table 5 | Comparison of Ramore TS options

Option	Capacity Impact	Estimated Cost	Lead Time
Distributed Energy Resources	Increase by 1.2 MW	$3 to $3.7 million	Three years
Station Upgrade	Increase by 15 MW	$10-15 million	Three years

NWA can be viable alternatives should demand grow as projected in Section 6.2.1.1. Otherwise, new solutions may have to be drawn up should a large industrial customer wish to connect to the station. Based on the options above, the Working Group recommends that the station loading at Ramore TS be monitored in between cycles in preparation for the next regional planning cycle.

7.1.2 A4H/A5H End-of-Life Needs

No other regional needs were identified that could be addressed by right-sizing the end-of-life replacement of the A4H/A5H circuits, based on the IRRP demand forecast. Therefore, the Working Group recommends that Hydro One proceed with a like-for-standard replacement for these end-of-life needs. Nonetheless, future system developments (e.g., additional demand growth or resource development in the area) could drive a need for reinforcement in this area in the future. Therefore, the Working Group recommends continued monitoring of developments in the area between regional planning cycles, and that Hydro One touch base with the Working Group before the like-for-standard replacement project is committed, to determine if this recommendation should be revisited.

7.1.3 D2H/D3H End-of-Life Needs

No other regional needs were identified in the IRRP that could be addressed by right-sizing the end-of-life replacement of the D2H/D3H circuits. The Working Group recommends that Hydro One proceed with a like-for-standard replacement for these end-of-life needs.

7.1.4 D3K Thermal Overload

This need was identified in the Needs Assessment stage of regional planning. Since that time, a new RAS has come into service in the Kirkland Lake area to maintain system reliability following various contingencies in the Kirkland Lake area. This RAS will be able to address the identified post-contingency overloading of D3K by arming load rejection for the appropriate A8K or A9K contingency. Therefore, at this time, the Working Group does not recommend any further actions to address this need.

However, the RAS may need to be expanded and/or the system may need to be reinforced should additional demand beyond what was included in the IRRP forecast connect to the system in the Kirkland Lake area. The Working Group recommends that this area be monitored in between regional planning cycles.

7.1.5 Ansonville, Hunta, Kapuskasing Area Voltage Control

The IRRP reviewed the post contingency voltages at Ansonville TS and Hunta SS following the loss of Ansonville T2 and Canyon GS units. The IRRP found that post contingency voltage levels meet ORTAC criteria (Hunta SS is permitted to operate up to 138 kV). Hydro One is currently studying a possible expansion to the Kirkland Lake RAS. This will allow operators to take control actions following the loss of Ansonville T2, among other contingencies. This will give more flexibility to operators should post contingency voltage issues be seen in the future. The Working Group recommends that Hydro One continue to study the possible expansion of the Kirkland Lake RAS. New reactive devices (a 10 MVAr reactor and a 10 MVAr capacitor), controlled by a new remedial action scheme will soon come into service in the Kapuskasing area. These improvements were designed to ensure voltage criteria is met following certain contingencies at Kapuskasing TS, Spruce Falls TS, and Pinard TS. No additional recommendations are required in this IRRP to address voltage control issues in the Kapuskasing area.

Additional reactive devices will be recommended in the Northern Voltage Study to support the broader bulk system across northern Ontario (see Section 4.2.2). The recommendations of this study will provide further reactive support to help alleviate voltage control issues in the North & East of Sudbury area.

7.2 Options and Recommendations for Meeting Longer-Term Needs

7.2.1 Dymond Area Voltage Control Needs

The Working Group recommends that Hydro One investigate right-sizing the capacitors at Dymond TS so that they may be used more effectively to manage voltage in the area. This can be accomplished by reducing the size of the existing capacitors to improve their flexibility. The Working Group recommends that the exact sizing be explored in the RIP in coordination with gathering information on feasible resizing options. The Working Group also recommends Hydro One investigate the feasibility of introducing remote monitoring of the status of the Dymond TS capacitor switching scheme to improve operational visibility.

7.2.2 Kirkland Lake Area Voltage Control Needs

Based on system studies performed in the IRRP, it was found that under the conditions noted in section 6.2.2.2, a 20 MVAr reactive device located at Kirkland Lake TS or a 10 MVAr reactive device at the remote end of circuit K2 would address this need. The Working Group recommends that Hydro One, in the upcoming RIP, further develop options for adding reactive support in the Kirkland Lake area.

7.3 Load Security

7.3.1 Considerations on existing reliance on Remedial Action Schemes in the Northeast and Load Security Needs

Several investments were made over the years to strengthen the area (e.g. Kapuskasing Area Reinforcement). Despite these investments, the reliability issues following the loss of D501P still remains. While proven reliable to protect the rest of the system, the continued long-term reliance on the Northeast LGR may hamper growing interest to connect additional loads (e.g. new mines, mining expansions) and generators in the area.

As the circuit D501P is part of the Bulk Power System, the Working Group recommends that the next bulk system plan in Northeast Ontario address the load security concerns following an outage on D501P. This bulk plan should be triggered if substantial load increases/new resources are expected in the Kapuskasing and northern Cochrane areas.

7.4 Summary of Recommended Actions and Next Steps

Table 6 below shows a summary of all recommended actions as outlined in Section 7.

Table 6 | Summary of Recommended Actions and Next Steps

No.	Need Description	Recommendation	Need Date
1	Station Capacity at Ramore TS	Load growth at Ramore TS will be monitored and revisited in the next cycle of regional planning	2033
2	Voltage control issues with existing capacitors at Dymond TS	Hydro One to investigate options to improve operability of existing capacitors in the upcoming RIP	2030
3	Voltage control issues in the Kirkland Lake area	Hydro One to investigate options of adding reactive devices in the Kirkland Lake area in the upcoming RIP	2030
4	Voltage control issues at Ansonville, Hunta, Kapuskasing Area	Various recommendations, including a new RAS and additional voltage support	Near to Mid-term
5	Thermal overload of circuit D3K upon loss of A8K or A9K when its companion is out of service	The new Kirkland Lake RAS installed in 2022 addresses this issue. Additional load in the area beyond the current forecast will require further study	2030
6	A4H/A5H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2027
7	D2H/D3H End-of-Life Need	Hydro One to proceed with plans to replace the affected circuit sections with a like-for-like replacement	2026
8	ORTAC load security criteria not met for 500 kV circuit outages	Partially addressed by the recent Northeast Bulk Plan. An update to this plan is recommended should significant new resources and/or load connect to the North & East of Sudbury region.	Existing Need

No.	Need Description	Recommendation	Need Date
9	Difficulty supplying loads during planned outages to circuit D501P	Study this need as part of the next bulk system plan for Northeast Ontario in combination with other drivers of system expansion as they develop	Existing Need

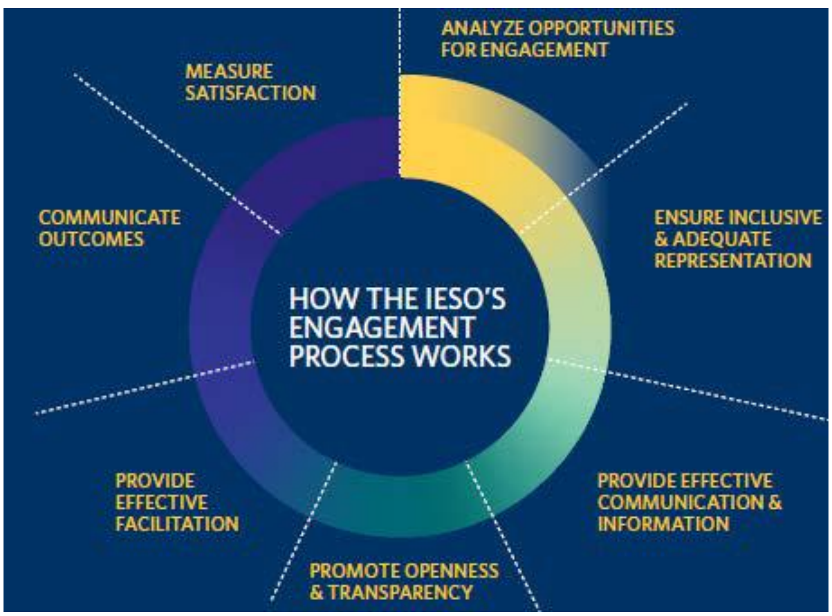
8. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken for the IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 11 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for North & East of Sudbury

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; and
- 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 to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars;
- Targeted individual and small group meetings; and
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (see Section 8.3).

8.3 Engage Early and Often

Preliminary discussions were held to help inform the engagement approach and lay the foundation for dialogue in this region where the IESO has not actively engaged with communities and stakeholders. This started with an invitation to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and opportunity to provide input on the North & East of Sudbury Region Scoping Assessment Outcome Report. A public webinar was held in June 2021 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach to address them moving forward. Interested parties were invited to submit written feedback on a draft report that was posted for review over a three-week comment period. The final Scoping Assessment was posted later in August 2021, identifying the need for a coordinated regional planning approach and an IRRP.

Following the publication of the final Scoping Assessment, targeted outreach began with municipalities in the region to inform early discussions in the development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed to ensure all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected over a 21-day comment period after each webinar.

The three stages of engagement at which input was invited:

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

Comments received were primarily focused on:

- Pockets of development in certain areas (I.e. City of Temiskaming Shores, Town of Iroquois Falls and Town of Moosonee)
- Interest in exploring DERs and other non wires alternatives to address regional needs and defer the need for new transmission or large scale generation
- Reliability is a key issue and priority
- Engagement with local First Nations communities, customers and stakeholders is important to understand planned growth and opportunities to participate in developing solutions to meet emerging needs.

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

All interested parties were kept informed throughout this engagement initiative via email to North & East of Sudbury subscribers, municipalities, and Indigenous and Métis communities. All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's North & East of Sudbury engagement webpage.

Ongoing discussions will be encouraged through the IESO's Northeast Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle. Join the Northeast Network on the IESO website**.**

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP.

This targeted outreach was undertaken in tandem with the Northeast Bulk Plan work and engagement given the interrelations of some of the needs at the provincial and regional level, as well as to streamline discussions with local communities. Discussions were held with the Federation of Northern Ontario Municipalities (FONOM) Board of Directors, City of Timmins, Town of Iroquois Falls and Town of Cochrane. These discussions helped to build an understanding about the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular communications were sent to Indigenous communities within the North & East of Sudbury electricity planning region or that may have interests in the region throughout the development of the plan. This includes the First Nation communities of Constance Lake First Nation, Flying Post First Nation, Matachewan First Nation, Mattagami First Nation, Missanabie Cree, Moose Cree First Nation, MoCreebec Council of the Cree Nation, Nipissing First Nation, Taykwa Tagamou First Nation, Temagami First Nation, Wahgoshig First Nation, Wahnapitae First Nation, Northern Lights Métis Council, Timmins Métis Council, Temiskaming Métis Council and Chapleau Métis Council. This electricity planning initiative was also discussed during broader outreach meetings with Indigenous communities in the region.

9. Conclusion

The North & East of Sudbury IRRP identifies electricity needs in the region and opportunities to improve system reliability and operability for the next 20 years. This report recommends a plan to address near- to medium-term issues, and lays out actions to monitor, defer, and/or address long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, and monitoring load growth. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The Technical Working Group will 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.

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