East Lake Superior Region

Scoping Assessment Outcome Report (DRAFT FOR REVIEW)

November 27, 2024

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Table of Contents

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process and sets out the planning approach to address electricity needs that have been identified in the East Lake Superior Region. The OEB started regional planning in 2011 and endorsed the Planning Process Working Group's Report to the Board in May 2013. The Board formalized the process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The current cycle of regional planning for the East Lake Superior Region started in June 2024. The Needs Assessment (NA) is the first step in the regional planning process and was carried out by the East Lake Superior Technical Working Group (TWG) led by Hydro One Networks Inc. (Hydro One). This report was finalized on October 9, 2024 and flagged several needs requiring further regional coordination as well as a few needs to be addressed by local planning. This information was an input to this Scoping Assessment Outcome Report.

As part of the Scoping Assessment, the TWG reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach to address them, including:

- An Integrated Regional Resource Plan (IRRP) – through which a greater range of options, including non-wires alternatives, are to be considered and/or closer coordination with communities and stakeholders is required
- A Regional Infrastructure Plan led by the transmitter – which considers more straight-forward wires only options with limited engagement
- A Local Plan undertaken by the transmitters and affected local distribution company or companies (LDC) – for which no further regional coordination is needed

This Scoping Assessment Outcome Report recommends an Integrated Regional Resource Plan (IRRP) for the East Lake Superior region focused on several specific needs that have been identified or raised by stakeholders through ongoing outreach and previous planning cycles.

This Scoping Assessment report is structured as follows:

- Section 2 lists the Technical Working Group
- Section 3 provides an overview of the region, the previous regional planning cycle, and major transmission reinforcements since the previous cycle
- Section 4 summarizes the new and updated needs as described in the Needs Assessment
- Section 5 describes the criteria used to select a regional planning approach and specifies the scope of the IRRP

Appendix 1 defines the acronyms used in this document and Appendix 2 establishes the draft Terms of Reference for the IRRP and the composition of the IRRP Technical Working Group.

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

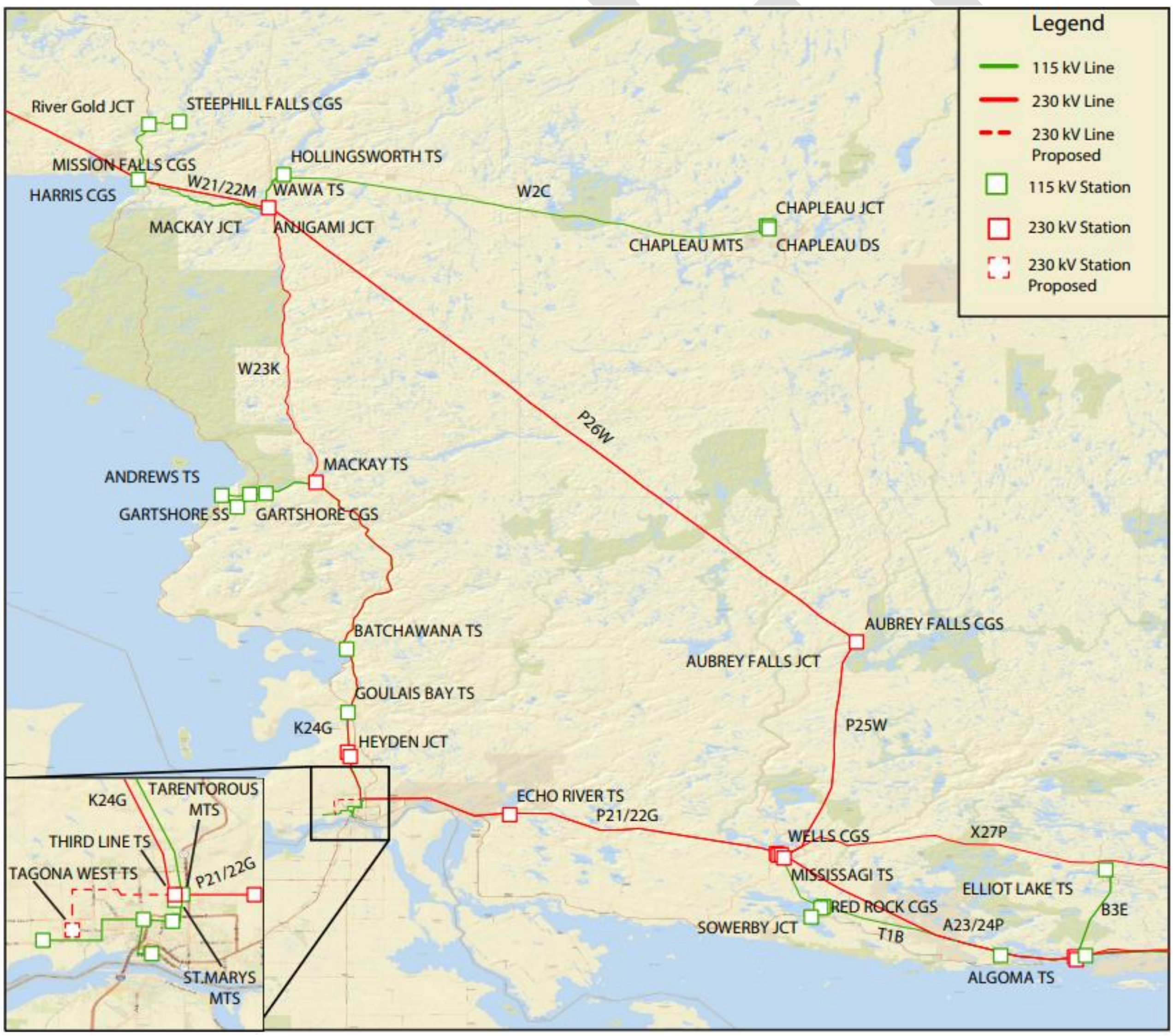
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. Transmission (HONI Tx)
- Hydro One Sault Ste. Marie LP Transmission (HOSSM)
- Hydro One Distribution (HONI Dx)
- Algoma Power Inc. (API)
- PUC Transmission
- PUC Distribution

3. Overview of Region and Background

The East Lake Superior region is in northeastern Ontario and includes the area roughly bounded by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south.

It includes the city of Sault Ste. Marie and the municipalities and townships of Bruce Mines, Chapleau, Hilton, Huron Shores, Jocelyn, Johnson, Laird, Macdonald, Meredith & Aberdeen Additional, Plummer Additional, Prince, St. Joseph, Tarbutt & Tarbutt Additional, Dubreuilville and Wawa. Indigenous communities include Chapleau Cree First Nation, Chapleau Ojibwe First Nation, Garden River First Nation, Michipicoten First Nation, Brunswick House First Nation and Batchewana First Nation.

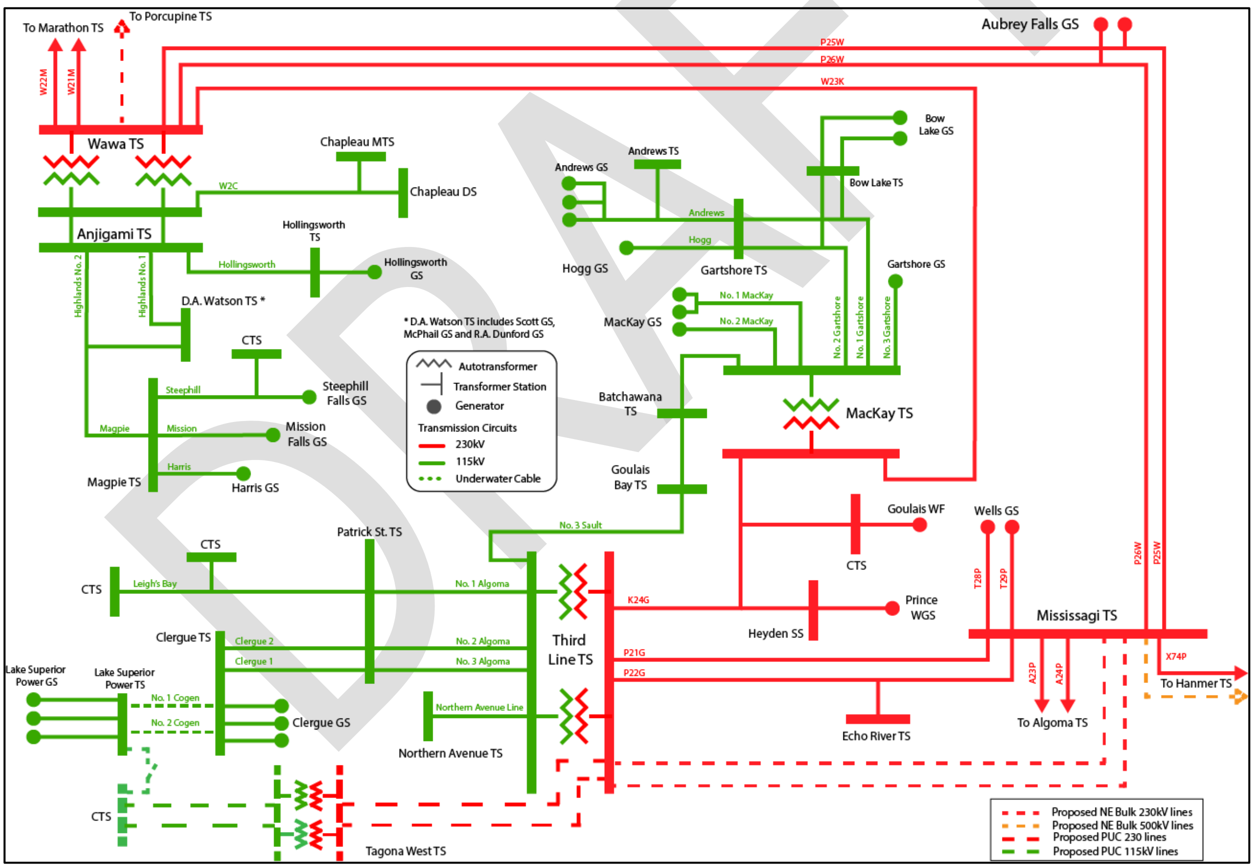
Figure 1 | East Lake Superior Region Area Map



Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region is served by three LDCs who form part of the TWG: Algoma Power Inc., PUC Distribution and Hydro One Distribution and three transmitters: PUC Transmission LP, Hydro One Sault Ste. Marie (HOSSM) and Hydro One Networks Inc. Electrical supply to the region is provided primarily through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities as seen in Figure 2. Third Line TS supplies mostly the load in the city of Sault Ste. Marie, Wawa TS supplies local load and connects local generation to the area, and Mackay TS connects local wind and hydro generation to the transmission network. The area map of the region is shown in Figure 1 and the single line diagram of the electrical infrastructure in the region is shown in Figure 2.

In this region, the electrical load is comprised of industrial, commercial and residential users and is winter peaking. The region has over 1,200 MW of generation, including numerous hydroelectric facilities, solar and wind farms and thermal generating facilities.

Figure 2 | East Lake Superior Region Transmission Single Line Diagram



3.1 Previous Regional Planning Cycle and Status Update

The previous cycle of regional planning for the ELS region was carried out during 2019- 2021. After reviewing the identified needs, the TWG decided that an IRRP was required for the region as the assessment of non-wires alternatives, co-ordination with upstream transmission system issues, and closer coordination with communities and stakeholders were required. The ELS IRRP was published in April 2021. The IRRP used a 20-year demand forecast to identify near, mid and long-term needs and made recommendations for addressing these needs. Some of the recommendations were to consider the needs as part of the IESO bulk system study for Northeast Ontario that commenced in 2021.

This Northeast bulk report was published in 2022 and it recommended the following infrastructure projects to supply growing electricity demand in Sault Ste. Marie and Timmins.

i. A new 500 kV line between Hanmer TS and Mississagi TS – Planned completion by 2029.

ii. A new 230 kV double circuit line between Mississagi TS and Third Line TS – Planned completion by 2029.

iii. A new 230 kV line between Porcupine TS and Wawa TS, built to operate at 500 kV in the future – Planned completion by 2030.

The recommendations made as part of the previous cycle of regional planning are summarized in Table 1 below. Note that these needs have evolved and recommendations were outlined in the Needs Assessment.

Table 1 | Recommendations from 2021 ELS IRRP

Need	Recommendation	Lead Responsibility	Required By
Loss of one Third Line TS autotransformer causes the companion autotransformer to be loaded close to its capacity	Monitor load and supply in the ELS region	IESO/HOSSM	Immediately and Ongoing
Loss of P21G/P22G circuits causes voltage collapse at Third Line TS and other ELS stations	Enable remote arming of GLP Instantaneous Load Rejection Scheme for P21G and P22G double contingency for operational efficiency over manual arming	Hydro One	Immediately
Loss of Algoma circuits or a Patrick St. TS 214 BKF results in thermal overload of the remaining circuit	Implement automatic load rejection scheme at Patrick St. TS	HOSSM	Immediately

Need	Recommendation	Lead Responsibility	Required By
During an outage of P25W pr P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No. 3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
During an outage to one of the Third Line TS autotransformers, loss of the companion autotransformer results in thermal overload of the Sault No. 3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2 and vice versa	Hydro One to work with the LDC to build a new 115/44 kV station that will tap off Hollingsworth 115 kV circuit to accommodate the load increase	HOSSM	2024

4. Needs Assessment Methodology

The first phase of the current regional planning cycle, the Hydro One-led Needs Assessment, was completed in October 2024.

This section briefly summarizes the needs identified in the Needs Assessment report. Please refer to the full Needs Assessment report for more details[1]. Section 5 specifies the planning approach and outlines the specific needs that will be in scope for subsequent regional planning stages.

4.1 Types of Electricity Needs

Based on the reference demand forecast (extreme weather, net demand), system capability, transmitters' identified end-of-life asset replacement plans, and the application of the IESO's Ontario Resource and Transmission Assessment Criteria[2], North American Electric Reliability Corporation's (NERC) Transmission System Planning Performance Requirements[3], and the Northeast Power Coordinating Council's (NPCC) Directory # 1 - Design and Operation of the Bulk Power System[4]. The Technical Working Group identified electricity needs which generally fall into the following categories:

- **Station Capacity Needs** arise when the demand forecast exceeds the electricity system's ability to deliver power to the local distribution network through the regional step-down transformer stations at peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be 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 ability 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 NERC/NPCC standards. LMC studies are conducted using power system simulation analysis.

[1] The 2024 East Lake Superior Region Needs Assessment Report is available on Hydro One's website (Link).
[2] The Ontario Resource and Transmission Assessment Criteria is available on the IESO's website (Link).
[3] The Transmission System Planning Performance Requirements is available on NERC's website (Link).
[4] The Directory #1 - Design and Operation of the Bulk Power System is available on NPCC's website (Link).

- **End-of-life Asset Refurbishment Needs** are identified by the transmitter with consideration to a variety of factors such as asset age, 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 condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. Note that IRRPs do not typically study and make recommendations for all end-of-life needs where like-for-like replacements have been established to be appropriate in earlier phases of the regional planning process.
- **Load Security and Restoration Needs** describe the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

4.2 Needs Not Requiring Further Regional Coordination

The East Lake Superior Needs Assessment determined that the needs listed in Table 2 do not require further regional coordination.

Table 2 | Needs Identified in Needs Assessment Not Requiring Regional Coordination

Need #	Need	Need Description	Proposed Solution
1	Hollingsworth TS Station Capacity Need	For loss of Anjigami TS, there is thermal overload on Hollingsworth TS.	Study through Local Planning.
2	Third Line TS auto-transformer Supply Capacity Need	Loss of one Third Line TS autotransformer causes companion to be overloaded.	Further monitor. Need appears in 2033 if Tarentorous MTS is not moved to new Tagona West TS.
3	Third Line TS voltage System Reliability Need	Third Line TS 115 kV is restricted to operate between 118 kV and 124 kV.	Further monitor until transformers are replaced with new units equipped with ULTC at St. Mary's MTS and Tarentorous MTS.

Need #	Need	Need Description	Proposed Solution
4	Tagona West TS auto-transformer Supply Capacity Need	Tagona West TS – 230/115 kV autotransformer overload upon the loss of companion unit.	To be resolved using a Load Rejection Remedial Action Scheme as part of the Connection Assessment and Approval process.

4.3 Needs Requiring Further Regional Coordination

The latest ELS Needs Assessment identified several issues that need to be addressed during this cycle of regional planning. It based its assessment on the most up-to-date sustainment, a new 10-year demand forecast provided by the LDCs, and updated conservation and demand management (CDM) and distributed generation (DG) forecasts provided by the IESO. The needs identified in the report that require further regional planning coordination are summarized below.

Table 2 | Needs Identified in Needs Assessment Requiring Regional Coordination

#	Need	Need Description	Timing
1	St Mary's MTS and Tarentorous MTS End-of-life Asset Refurbishment Needs	Assets approaching end-of-life and need to be replaced.	Near Term
2	Algoma circuit overload Supply Capacity Need	Algoma No.1/ No.2/ No.3 – circuit overload after loss of any two Algoma circuits.	Near Term
3	Sault No. 3 circuit overload Supply Capacity Need	During an outage to P25W or P26W, loss of K24G can result in an overload of Sault No.3.	Near Term
4	Voltage violation at Third Line TS Supply Capacity Need	After loss of both Third Line autotransformers, will result in voltage collapse. Also, the loss of P21G/P22G will result in a severe voltage decline at Third Line TS.	Near Term

4.3.1 St Mary's MTS and Tarentorous MTS station End-of-life

St Mary's MTS and Tarentorous MTS are 115/34.5 kV transformer stations owned by PUC Distribution in the city of Sault Ste. Marie. They are supplied by Third Line TS through two 115 kV circuits and each having four 30 MVA step-down transformers. These stations are approaching end-of-life. PUC is planning on retiring Tarentorous MTS and moving its load to a new Tagona West TS while rebuilding St Mary's MTS. Moving the Tarentorous MTS load to Tagona West TS would bring the load to 95% of the LTE rating at Third Line TS considering Sault No. 3 operates in a network configuration.

4.3.2 Algoma Circuit Overload

There are three 115 kV circuits supplying Patrick St TS from the Third Line 115 kV bus, Algoma No.1, Algoma No.2 and Algoma No.3. The loss of any two Algoma circuits will overload the remaining Algoma circuit beyond its STE rating. Currently, this need is mitigated by manual load curtailment at Patrick St. TS, when any of the Algoma circuits are out of service. A new Remedial Action Scheme (RAS) is being installed in Q1 2025 at Third Line TS to cross-trip remaining Algoma circuit when two other circuits are out of service.

4.3.3 Sault No. 3 circuit overload

Sault No.3 is a 115 kV circuit that connects Third Line TS to Mackay TS in the East Lake Superior region and supplies two connected load stations, Batchawana TS and Goulais Bay TS. Hydro One Sault Ste. Marie LP. (the "transmitter") is refurbishing the 115 kV circuit, Sault No. 3, and will reconnect Sault No. 3 in parallel with K24G 230 kV circuit, in a network configuration. The proposed in-service date for this refurbishment is Q2 2026. Today, Sault No. 3 is operated radially open at Mackay TS.

During an outage to either the P25W or P26W circuit between Wawa TS to Mississagi TS, a contingency on the K24G circuit between Third Line TS and Mackay TS results in the thermal overload of the Sault No.3 circuit beyond its STE ratings. This issue was identified in the previous regional cycle and the recommendation was to consider it as part of the 2022 IESO Northeast Bulk Planning Study. The IESO's Northeast Bulk Planning Study considered the upgrade of the Sault No.3 circuit to 230 kV but found that, on its own, this option would not address the identified bulk system needs. The observed bulk system limitations were between Mississagi TS and Third Line TS, not between Third Line TS and Mackay TS. As a result, the needs carried forward from the IRRP remained unaddressed.

The refurbishment on Sault No. 3 will include a Mackay RAS modification to cross-trip Sault No. 3 for the contingency on the K24G circuit. The current Mackay RAS ensures that the post contingency load on Sault No. 3 115 kV line is within its continuous rating for the loss of Mackay TS T2 or for the loss of K24G.

4.3.4 Voltage violations at Third Line TS

Third Line TS has a set of 230/115 kV autotransformers T1 and T2 rated at 250 MVA which supply most of the load in the city of Sault Ste. Marie. With one Third Line autotransformer out of service, the loss of companion autotransformer will result in severe voltage decline at Third Line TS and Sault No. 3 circuit being overloaded.

Also, the loss of P21G and P22G circuits running from Third Line TS to Mississagi TS will result in a severe voltage decline at Third Line TS today. New circuits P23G and P24G will be built as part of the Northeast Bulk Planning Study and likely mitigates this need.

5. Regional Planning Approach

Needs identified through the Needs Assessment (NA) were reviewed during the Scoping Assessment to determine whether a Local Plan ("LP"), Regional Infrastructure Plan ("RIP"), or Integrated Regional Resource Plan ("IRRP") regional planning approach is most appropriate. An Integrated Regional Resource Plan is recommended for the East Lake Superior region. The Needs Assessment flagged several needs that may require further regional coordination and has potential impacts to the bulk system. Upon further consideration, this Scoping Assessment concurs with the Needs Assessment. Additionally, there is a high degree of stakeholder and community interest. The following sections outline the selection criteria, and the scope of the recommended IRRP.

5.1 Selection Criteria

The three potential planning outcomes are designed to carry out different functions and selection should be made based on the unique needs and circumstances in each area. The criteria used to select the regional planning approach within each sub-region are consistent with the principles laid out in the Planning Process Working Group Report to the Board[5], and are discussed in this document to ensure consistency and efficiency throughout the Scoping Assessment.

IRRPs are comprehensive undertakings that consider a wide range of potential solutions to determine the optimal mix of resources to meet the needs of an area for the next 20 years, including consideration of non-wires alternatives, conservation, generation, new technologies, and wires infrastructure. RIPs focus instead on identifying and assessing the specific wires alternatives and recommend the preferred wires solution for an area and are thus narrower in scope. LPs have the narrowest scope; only considering simple wires solutions that do not require further coordinated planning.

A LP process is recommended when needs:

- Are local in nature (only affecting one LDC or customer)
- Are limited investments of wires (transmission or distribution) solutions
- Do not require upstream transmission investments
- Do not require plan level community and/or stakeholder engagement and,
- Do not require other approvals such as a Leave to Construct application or Environmental Approval.

[5] The Planning Process Working Group Report to the Board is available on the OEB's website (Link).

If it is determined that coordinated planning is required to address identified needs, either a RIP or an IRRP may be initiated. A series of criteria have been developed to assist in determining which planning approach is the most appropriate based on the identified needs. In general, an IRRP is initiated wherever:

- A non-wires measure has the potential to meet or significantly defer the needs identified by the transmitter during the Needs Assessment;
- Community or stakeholder engagement is required; or,
- The planning process or outcome has the potential to impact bulk system facilities

If it is determined that the only feasible measures involve new/upgraded transmission and/or distribution infrastructure, with no requirement for engagement or anticipated impact on bulk systems, a RIP will be selected instead.

Wires type transmission/distribution infrastructure solutions refer, but are not limited, to:

- Transmission lines
- Transformer/ switching stations
- Sectionalizing devices including breakers and switches
- Reactors or compensators
- Distribution system assets

Additional solutions, including conservation and demand management, generation, and other electricity initiatives can also play a significant role in addressing needs. Because these solutions are non-wires alternatives, they must be studied through an IRRP process.

5.2 Integrated Regional Resource Plan Scope of Work

Note that the primary purpose of an IRRP is to study needs that require coordination between transmitters, distribution companies, and the IESO. The IRRP will not study bulk system needs such as transfer capability on the 230 kV system such as those studied as part of the IESO's Need for Northeast Bulk System Reinforcement[6]. However, the load forecast developed during the IRRP will inform bulk system studies. Additionally, the IRRP will not specifically address new customer transmission connection requests unless there is an opportunity to align with broader regional needs. While the IRRP welcomes information from project proponents to inform load forecasting and to ensure plans for regional infrastructure are adequate, individual customers connection requests may be better suited for a proponent driven Technical Feasibility Study.

The IRRP will focus on the needs described below.

[6] More information about the Need for Northeast Bulk System Reinforcement is available on the IESO's website (Link).

Sault Ste. Marie Area Capacity Need

The Needs Assessment identified a potential capacity need at Third Line the associated downstream 115 kV system. Specifically, the study will examine and address:

- St Mary's MTS and Tarentorous MTS EOL
- Algoma circuit overload
- Sault No. 3 circuit overload
- Voltage violation at Third Line TS

Third Line and Tagona West TS are the primary supply points for the City of Sault Ste. Marie and surrounding area. The IRRP will further study drivers of load growth and the timing of the need. The St Mary's MTS and Tarentorous MTS station End-of-life needs will be prioritized in the IRRP to support PUC's upcoming regulatory approvals with the Ontario Energy Board in 2025.

6. Conclusion and Next Steps

This Scoping Assessment concludes that a IRRP covering the entire region will be undertaken to address the Sault Ste. Marie Area Capacity Need as discussed according to Section 5.2.

As further technical studies and community engagement are undertaken through the IRRP, new needs may come to light and be included in the scope of the IRRP. Additionally, the IRRP process is expected to be carried out in a manner that allows for continuous coordination of information with ongoing bulk system studies, such as the Northern Ontario Bulk Study. The draft Terms of Reference for the East Lake Superior IRRP can be found in Appendix 2.

Furthermore, this Scoping Assessment concurs with the Needs Assessment recommendation to address the Hollingsworth TS station capacity need through local planning, and the Tagona West TS auto-transformer Supply Capacity Need through the Connection Assessment and Approval Process.

Appendix 1 – List of Acronyms

Acronym	Definition
API	Algoma Power Inc
CDM	Conservation and Demand Management
DG	Distributed Generation
EAF	Electric Arc Furnace
ELS	East Lake Superior
HOSSM	Hydro One Sault Ste. Marie
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Mega Volt-Ampere
MW	Megawatt
NA	Needs Assessment
RAS	Remedial Action Scheme
TS	Transformer Station
TWG	Technical Working Group
ULTC	Under Load Tap Changer

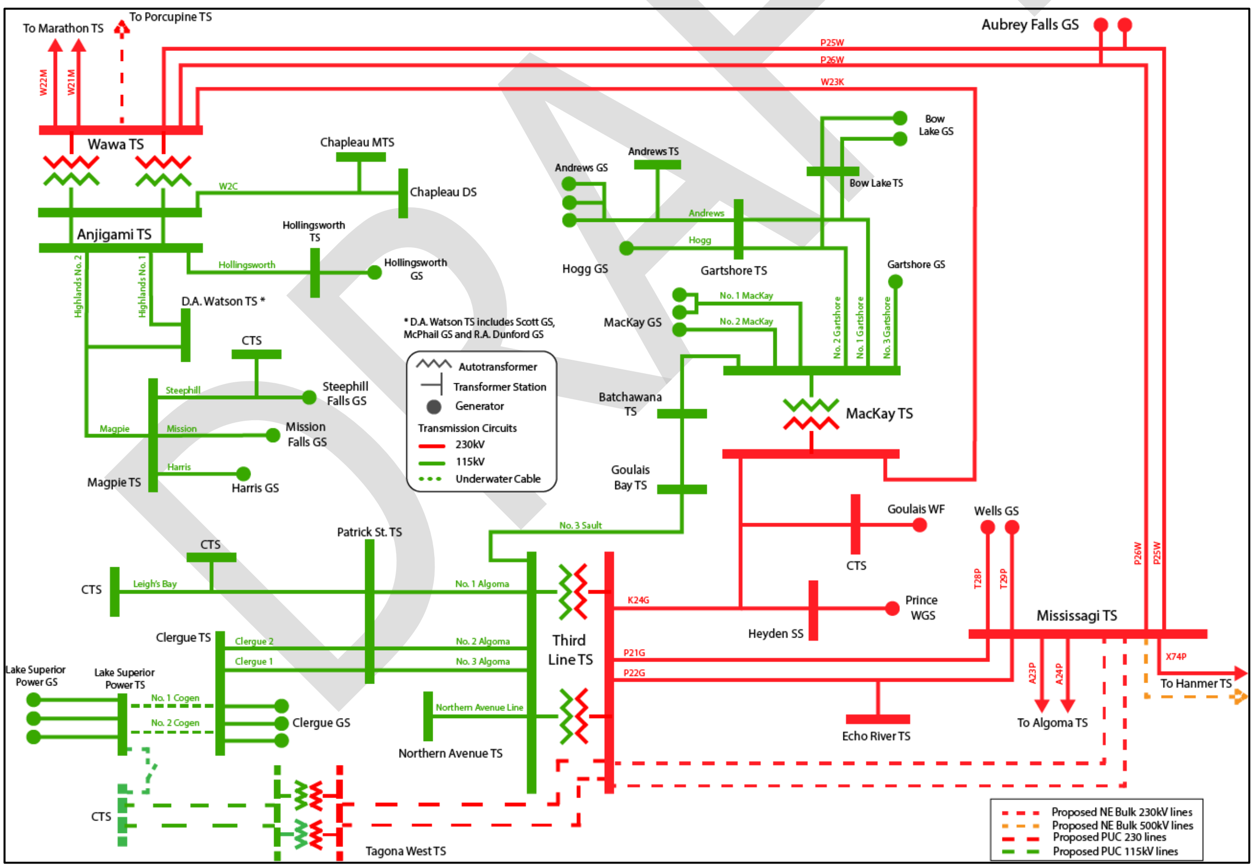
Appendix 2 – ELS IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) of the East Lake Superior region.

Based on the potential for demand growth within this region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended. The single line diagram is shown in Figure A-1.

Figure A-1 | East Lake Superior Region Transmission Single Line Diagram



The region encompasses the City of Sault Ste. Marie and surrounding areas. For electricity planning purposes, the region is defined by electricity infrastructure boundaries, not municipal boundaries. It is one of four planning regions in Northeastern Ontario, adjacent to the North East of Sudbury region to the east.

The following infrastructure is within the scope of this plan:

- 230 kV connected stations – Echo River TS, Tagona West TS[7]
- 115 kV connected stations – Andrews TS, Anjigami TS, Batchawana TS, Chapleau DS, Chapleau MTS, Clergue TS, D.A. Watson TS, Echo River TS, Gartshore TS, Gartshore SS, CTS1, CTS2, CTS3, CTS4, CTS5, Goulais Bay TS, Heyden CSS, Hollingsworth TS, Hwy 101 SS, Magpie TS, Northern Ave. TS, Patrick ST. TS
- 230 kV transmission lines – P21G, P22G; P25W, P26W; K24G; W23K;P23G, P24G[8]; Third Line x Tagona West
- 115 kV transmission lines – Sault No.3, Algoma No.1 / No.2 / No.3, Northern Ave 115kV, GL1SM, GL2SM, GL1TA, GL1TA, Leigh's Bay 115kV, Clergue No.1 / No.2, Mackay No.1 / No.2, Gartshore No.1 / No.2, Hogg 115kV, Andrew 115kV, Mission falls 115kV, Steephill 115kV, Harris 115kV, Magpie 115kV, High Falls No.1/No.2, Hollingsworth 115kV
- 230/115 kV autotransformers - Wawa TS, Mackay TS, Third Line TS

In October 2024, Hydro One completed the Needs Assessment report for the ELS region. Several needs were identified, and a Scoping Assessment was subsequently commenced to determine the preferred planning approach. An IRRP is ultimately recommended on the basis that many changes have taken place in the region included the new Tagona West TS and the circuits recommended from the Northeast Bulk Planning Study. These changes need to be analyzed to ensure that needs are addressed effectively.

2. Objectives

The East Lake Superior IRRP will assess the adequacy of electricity supply to customers in the region and will develop a set of recommended actions to maintain reliability of supply to the region over the next 20 years.

- Assess the adequacy of electricity supply to customers in the East Lake Superior area over the next 20 years;
- Determine whether there is a need to initiate development work or to fully commit infrastructure investments in this planning cycle;
- Identify and coordinate major asset renewal needs with regional needs, and develop a flexible, comprehensive, integrated electricity plan for East Lake Superior; and,
- Develop an implementation plan that is flexible to accommodate changes in key assumptions over time, while keeping options viable.

[7] Tagona West TS is the new PUC station coming into service in 2025

[8] P23G and P24G are the new 230 kV circuits from Mississagi TS to Third Line TS coming into service in 2029

3. Scope

The IRRP will develop and recommend an integrated plan to meet the needs of the ELS region. The plan is a joint initiative led by the IESO and completed by the members of the TWG. The plan will consider the demand forecast for the region, the CDM, DER uptake, transmission, and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable. The ELS IRRP aims to address the following needs, as identified in the 2024 Needs Assessment.

Table A-1 | Needs Requiring Further Regional Coordination

#	Need	Need Description	Timing
1	St Mary's MTS and Tarentorous MTS EOL	Assets approaching end-of-life and need to be replaced	Near Term
2	Algoma circuit overload	Algoma No.1/ No.2/ No.3 – circuit overload after loss of any two Algoma circuits.	Near Term
3	Sault No. 3 circuit overload	During an outage to P25W or P26W, a loss of K24G can result in an overload of Sault No.3.	Near Term
4	Voltage violation at Third Line TS	After loss of both Third Line autotransformers, will result in voltage collapse. Also, the loss of P21G+P22G will result in a severe voltage decline at Third Line TS.	Near Term

Other identified needs in the Needs Assessment not listed in the above table require monitoring or will proceed with Local Planning or Regional Infrastructure Planning as appropriate. Hydro One will keep the TWG informed on project development.

Based on the identified needs, the East Lake Superior IRRP process will consist of the following activities:

1. Develop an electricity demand forecast for the ELS region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region.

2. Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    a. Transformer, line and cable continuous ratings, long-term and short-term emergency ratings
    b. Known reliability issues and load transfer capabilities
    c. Customer load breakdown by transformer station
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station
3. Perform assessments of the capacity, reliability, and security of the electric power system under each demand outlook scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios
    b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them
4. Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    a. Collect information about the attributes of each option: cost, performance, timing, risk, etc
    b. Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives
    c. Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand
5. Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
6. Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.
7. Develop a long-term plan for the electricity system in the ELS region address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    a. Discuss possible ways the power system in the ELS region could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector
    b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement

8. Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

In order to carry out this scope of work, the Working Group will consider the data and assumptions outlined in section 4 below.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident peak demand information
    - Historical weather data (temperature, humidity, consecutive cooling/heating days, etc.) for the purpose of correcting demand for median/extreme weather conditions
    - Gross peak demand forecast scenarios by sub-region, TS, etc.
    - Identified potential future load customers
- Conservation and Demand Management
    - Conservation forecast for LDC customers, based on sub-region's share of current energy efficiency programs
    - Local Achievable Potential Studies
    - Potential for CDM at transmission-connected customers' facilities
- Local resources
    - Existing local generation, including distributed generation (DG), district energy, customerbased generation, Non-Utility Generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans, Municipal Energy Plans and Climate Action Plans
    - Municipal Growth Plans
    - Indigenous Community Energy Plans
- Criteria, codes and other requirements

  - Ontario Resource and Transmission Assessment Criteria (ORTAC)
  - NERC and NPCC reliability criteria, as applicable
  - OEB Transmission System Code
  - OEB Distribution System Code
  - Reliability considerations, such as the frequency and duration of interruptions to customers
  - Other applicable requirements
- Existing system capability
  - Transmission line ratings as per transmitter records
  - System capability as per current IESO PSS/E base cases
  - Transformer station ratings (10-day LTR) as per asset owner
  - Load transfer capability
  - Technical and operating characteristics of local generation
  - Bulk System considerations to be applied to the existing area network
- End-of-life asset considerations/sustainment plans
  - Transmission assets
  - Distribution assets
- Other considerations, as applicable

5. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Hydro One Networks Inc. Transmission (HONI)
- Hydro One Sault Ste. Marie LP Transmission (HOSSM)
- Hydro One Distribution
- Algoma Power Inc. (API)
- PUC Transmission
- PUC Distribution
- Independent Electricity System Operator (IESO)

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. As such, the IESO, in consultation with the Technical Working Group, is committed to conducting engagement in accordance with IESO Engagement Principles throughout the development of the IRRP.

The first step in engagement will consist of the development of an engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timelines and Primary Accountabilities

Table A-2 | IRRP Timelines & Activities

Activity	Lead	Deliverable	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	Q4 2024
2. Develop planning forecast scenarios for ELS region		Planning forecast scenarios	Q1 2025
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	LDCs		
d. Establish existing, committed, and potential DG	LDCs		

Activity	Lead	Deliverable	Timeframe
e. Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	LDCs/ Transmission	Load transfer capabilities under normal and emergency conditions	Q2 2025
4. Provide and review relevant community plans, if applicable	LDCs, indigenous communities, and IESO	Relevant community plans	Q2 2025
5. Complete system studies to identify needs over a 20-year time horizon Obtain PSSE base case Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios Confirm and refine the needs and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q2-Q4 2025
6. Develop options and alternatives		Flexible planning options for forecast scenarios	Q3-Q4 2025
a. Conduct a screening to identify which wire and non-wires options warrant further analysis	IESO		
b. Produce hourly forecasts for each transformer station to enable detailed needs characterization and support options development	IESO		
c. Develop energy efficiency options	IESO and LDCs		
d. Develop local generation/demand management options	IESO and LDCs		

Activity	Lead	Deliverable	Timeframe
e. Develop transmission and distribution alternatives (i.e. alignment with EOL sustainment plans, load transfers)	IESO and transmission		
f. Develop portfolios of integrated alternatives	TWG		
g. Technical comparison and evaluation	TWG		
7. Plan and undertake community and stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Metis Nations of Ontario	Ongoing as required
a. Early engagement with local communities and First Nation communities within ELS study area or who may have in interest in the study area	TWG		
b. Develop communications materials	TWG		
c. Undertake community and stakeholder engagement	TWG		
d. Summarize input and incorporate feedback	TWG		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q4 2025-Q1 2026

Activity	Lead	Deliverable	Timeframe
9. Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties	IESO	IRRP report	Q2 2026 – July 2026

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

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

ieso.ca

@IESO_Tweets
linkedin.com/company/IESO

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