East Lake Superior Region Scoping Assessment Report

October 4, 2019

Table of Contents

East Lake Superior Region Scoping Assessment Report 1
1 Introduction 3
2 Study Team 4
3 Categories of Needs, Analysis and Results 5
3.1 Overview of the Region 5
3.2 Background 8
3.3 Needs Identified 8
3.4 Other Needs and Considerations 10
3.5 Analysis of Needs and Planning Approach 11
4 Conclusion 12
List of Acronyms 13
Appendix A: The East Lake Superior IRRP Terms of Reference 14
Appendix B: Selecting a Regional Planning Approach 25

Summary			
Region	East Lake Superior		
Start Date	July 2, 2019	**End Date**	October 3, 2019

1 Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB) regional planning process. The OEB endorsed the Planning Process Working Group's Report[1] in May 2013 and formalized the process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first cycle of the regional planning process for the East Lake Superior (ELS) region was completed in December 2014. The 2014 Needs Assessment (NA) recommended that the potential needs identified be addressed through the development of localized wires-only solutions. Further coordinated regional planning did not proceed following publication of the 2014 ELS NA report.

The second cycle of regional planning for the ELS region was initiated in April 2019 with the NA process. The first step in the regional planning process, the NA was carried out by the Study Team (defined in Section 2), and the resulting NA[2] report – which identified needs to be considered in the Scoping Assessment to determine the appropriate process to address them – was completed and issued in June 2019.

During the Scoping Assessment, the Study Team reviewed the nature and timing of the known needs in the region to determine the most appropriate planning approach going forward. This process also identified needs and considerations that were not included in the NA. The planning approaches considered include:

- An Integrated Regional Resource Plan (IRRP) – where a greater range of options, including non-wires, are considered and/or closer coordination with communities and stakeholders is required;
- A Regional Infrastructure Plan (RIP) – which considers more straightforward wires-only options with limited engagement; or
- A local plan undertaken by the transmitter and affected local distribution company (LDC)– where no further regional coordination is needed.

Additional information on selecting a planning approach can be found in Appendix B.

This Scoping Assessment report:

- Lists the needs identified in the NA report;
- Describes additional needs and considerations not identified in the NA report;
- Defines the geographic grouping of the needs into sub-regions, as applicable;
- Determines the appropriate regional planning approach and scope for identified needs;
- Creates a terms of reference for an IRRP; and
- Establishes the composition of the IRRP Working Group.

---

[1] Planning Process Working Group Report to the Board - The Process for Regional Infrastructure Planning in Ontario

[2] Needs Assessment Report - East Lake Superior Region

2 Study Team

The Scoping Assessment was carried out by the Study Team:

- Independent Electricity System Operator (IESO) (project lead)
- Hydro One Networks Sault Ste. Marie LP (HOSSM) (transmitter)
- Hydro One Networks Inc. (HONI) (transmitter)
- Algoma Power Inc.
- Chapleau PUC
- Hydro One Distribution
- Sault Ste. Marie PUC (SSM PUC)

3 Categories of Needs, Analysis and Results

3.1 Overview of the Region

The ELS region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically 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.

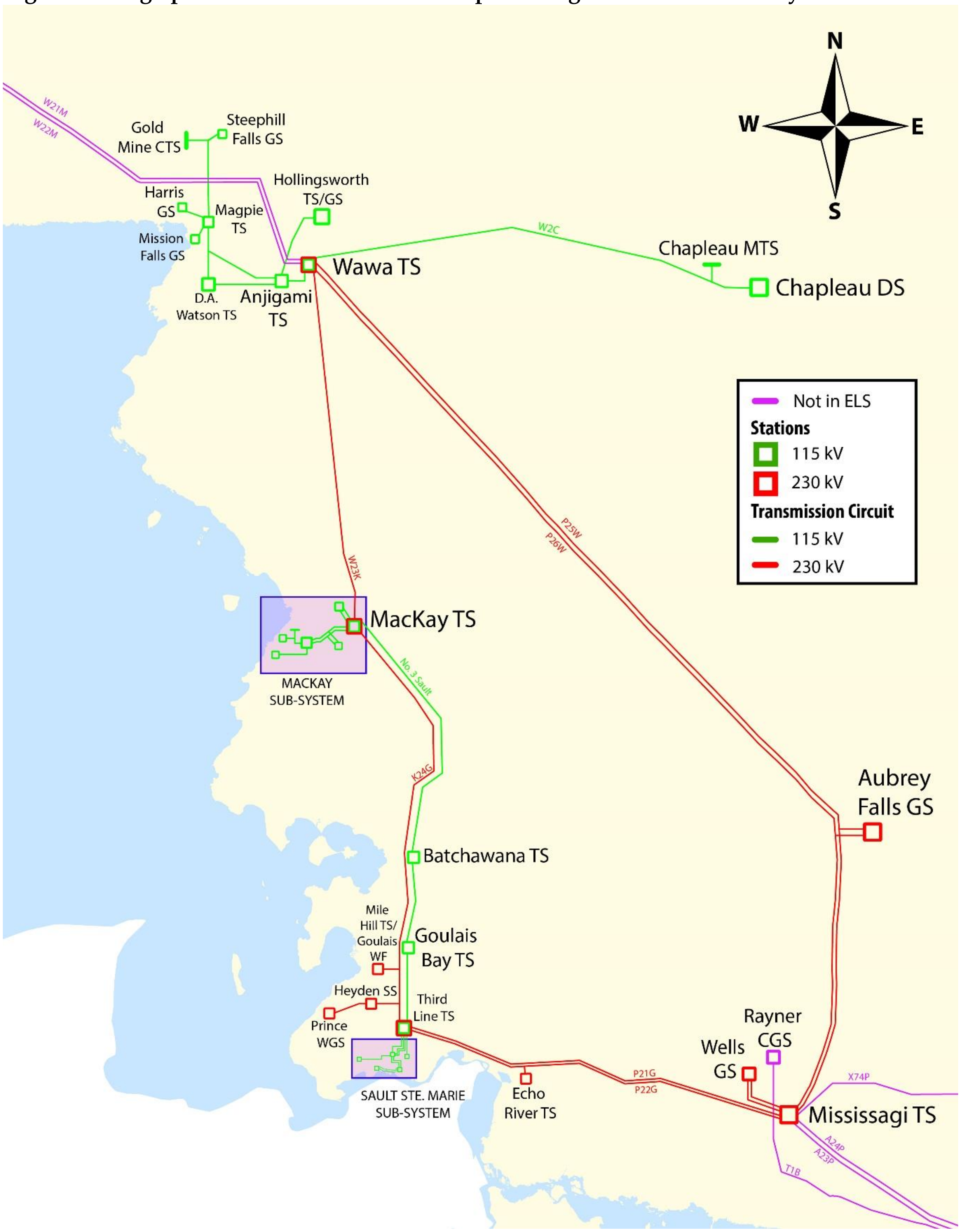
Electrical supply to the region is provided primarily through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figures 1 and 2. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both bulk system and regional system functions. That is, in addition to delivering reliable supply to local customers, they also form part of an integrated network that enables the bulk transfer of electricity across the province. Although the bulk transmission system is not the focus of regional planning, it impacts how the system is modelled and studied.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, solar and wind farms and thermal generating facilities. The transmitters in the region are Hydro One Sault Ste. Marie LP (HOSSM) and Hydro One Networks Inc. (Hydro One); the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and Sault Ste. Marie PUC.

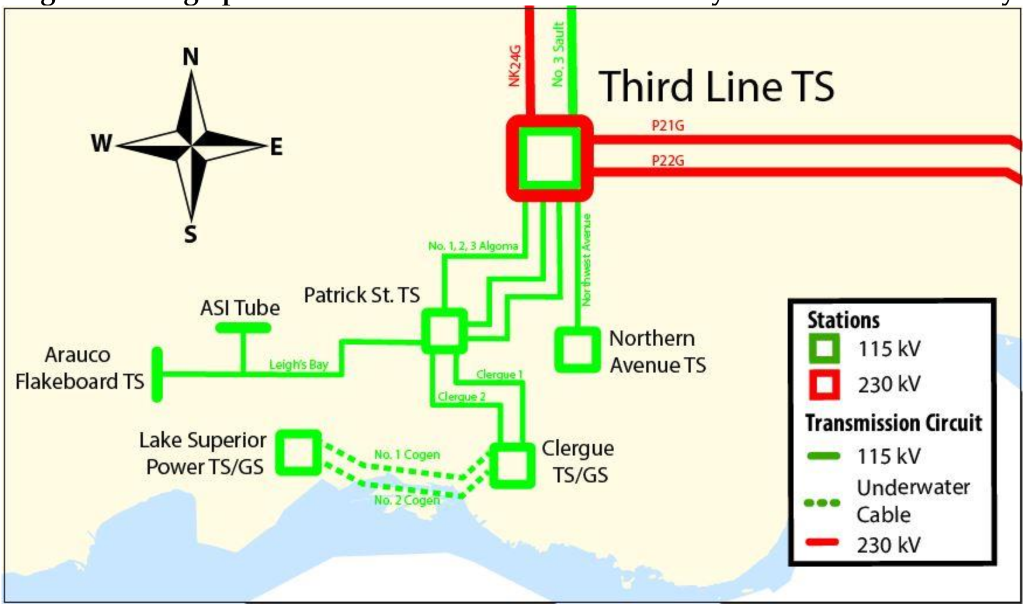
Geographic layouts of the electricity infrastructure supplying the region are shown in Figures 1, 2 and 3. An electrical single line diagram (SLD) for the same area is shown in Figure 4.

Figure 1: Geographical Area of the East Lake Superior Region with Electrical Layout



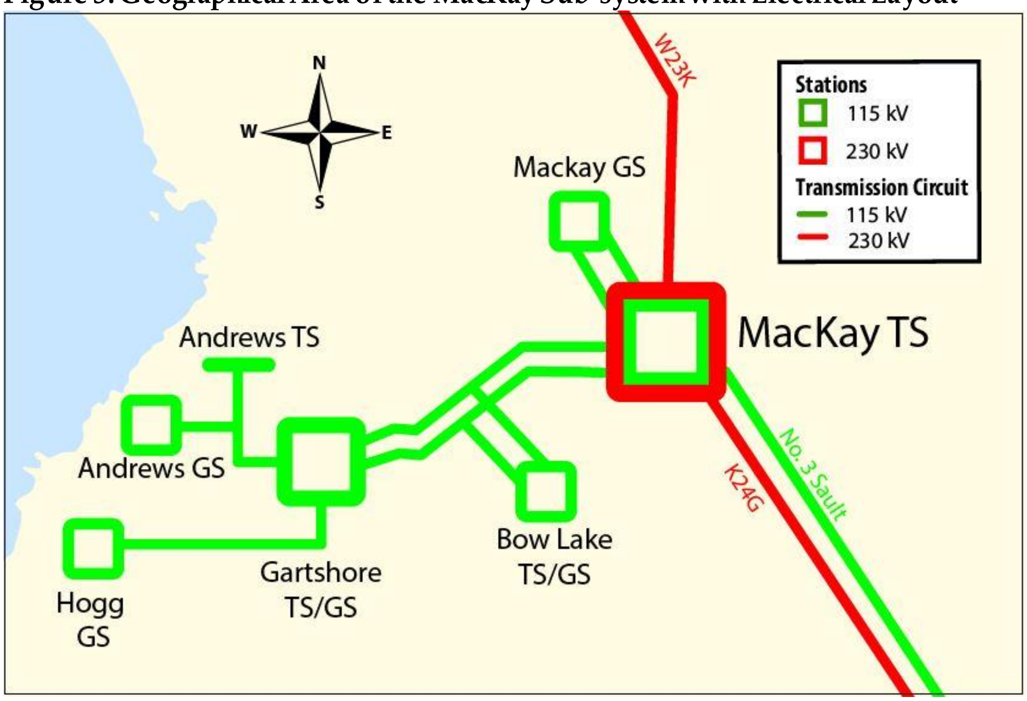
Source: IESO

Figure 2: Geographical Area of the Sault Ste Marie Sub-system with Electrical Layout



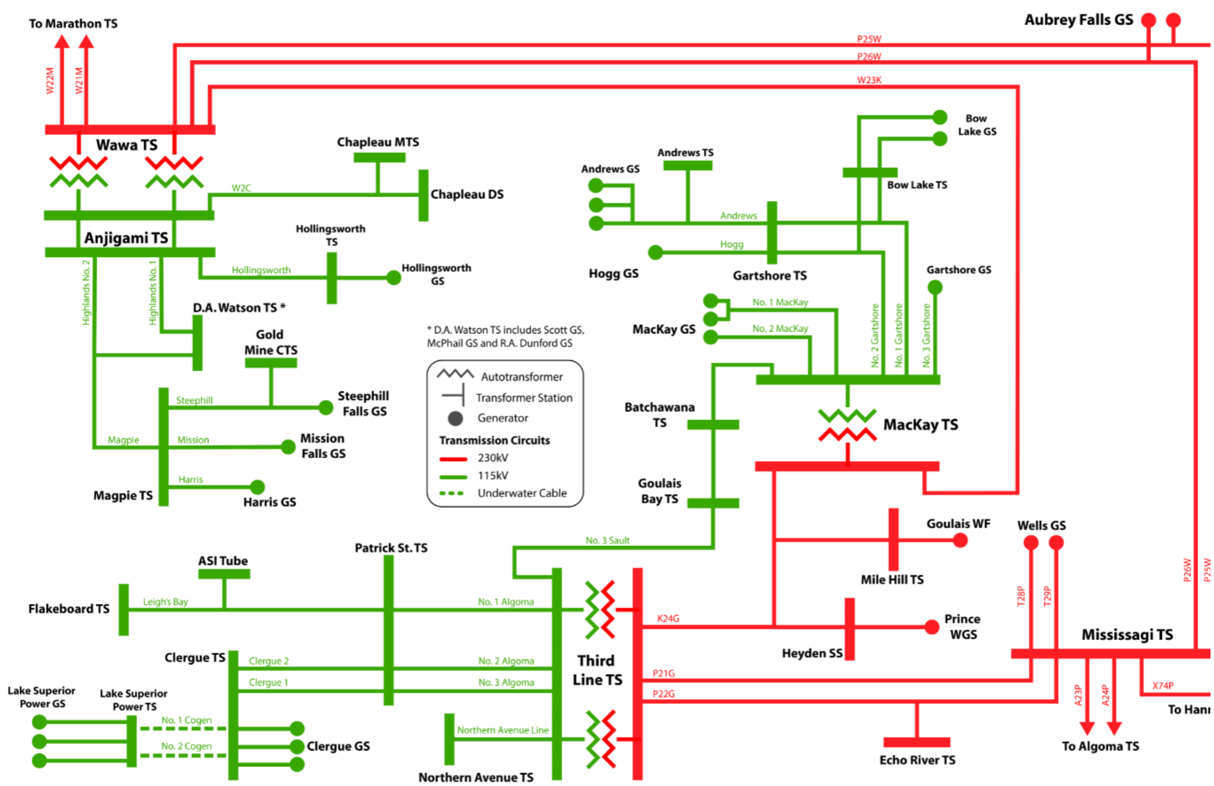
Source: IESO

Figure 3: Geographical Area of the MacKay Sub-system with Electrical Layout



Source: IESO

Figure 4: East Lake Superior Region Single Line Diagram



Source: IESO

3.2 Background

The first cycle of the regional planning process for the region was initiated by the former Great Lakes Power Transmission (GLPT) in October 2014 and completed in December 2014 with the publication of the 2014 NA report. The report identified a number of potential needs and recommended addressing them through the development of localized wires-only solutions. Further coordinated regional planning did not proceed following publication of the report.

In 2016, Hydro One acquired GLPT and renamed the company Hydro One Sault Ste. Marie LP. The second cycle of regional planning was kicked off by HOSSM in April 2019 and the 2019 NA report was published in June 2019. The needs identified in this report form the basis of the analysis for this Scoping Assessment and are discussed in further detail in Section 3.3.

3.3 Needs Identified

The 2019 NA report identified a number of needs based on studies performed during the needs assessment phase, current sustainment plans and a 10-year demand forecast. This section describes those needs.

3.3.1 Third Line TS Autotransformer Overload

Following the loss of one autotransformer at Third Line TS, the second autotransformer is expected to exceed its 10-day limited time rating (LTR) by 2022.

This need is exacerbated by the poor condition of the 115 kV circuit Sault No. 3, which is currently operated open until the conductor is replaced. The conductor is expected to be replaced by 2022 allowing it to be operated closed. This will reduce the need at Third Line TS, reducing loading on the autotransformers to 94 per cent of their 10-day LTR.

3.3.2 No. 1 Algoma Overload

No.1 Algoma is one of three 115 kV circuits supplying Patrick St TS from the Third Line 115 kV bus. Based on today's load, the loss of circuits No.2 Algoma and No.3 Algoma, or a breaker failure at Patrick St TS, can results in flows on No.1 Algoma exceeding the long-term emergency rating of the line.

3.3.3 Load Security and Restoration

Load restoration capability is the ability to restore power to those affected by a transmission outage within reasonable time frames. A restoration need emerges when load is interrupted following a transmission outage and supply cannot be restored within the timelines specified by the applicable planning criteria. These timelines are dependent on the amount of load being interrupted and proximity to maintenance crew and centres.

Load security needs emerge if the total amount of electricity supply at risk of interruption following a transmission outage exceeds the amounts permissible by the applicable planning criteria. The criteria identify areas where a supply outage could affect a vast number of customers, regardless of restoration time. Details on planning contingencies that must be considered, and associated restoration and security guidelines, are defined in Ontario Resource and Transmission Assessment Criteria (ORTAC).

The NA report identified load restoration needs following the loss of the step-down transformers at Andrew TS, Batchawana TS, Echo River TS or Goulais TS.

The NA report did not identify any load security needs; however subsequent studies identified a potential load security need[3] in the Sault Ste. Marie sub-system following the loss of both autotransformers[4] at Third Line TS.

3.3.4 End-of-Life Facility Needs

The need to replace aging transmission assets may present opportunities to better align investments with evolving power system priorities. This may involve up-sizing equipment in areas with capacity needs, downsizing or even removing equipment that is no longer required to supply needs.

---

[3] Ontario Resource and Transmission Assessment Criteria, Section 7.1, Load Security Criteria

[4] North American Electric Reliability Corporation (NERC) Standard TPL 001-4, Category P6 – Multiple Contingency (Two overlapping singles)

Facilities anticipated to be approaching end of life are summarized in Table 1.

Table 1: End-of-Life Facilities

Facilities	Target Date
DA Watson TS – Protection Upgrade	2019 (underway)
Echo River TS – Breaker Replacement	2021
Sault No. 3 Conductor and Structure Replacement	2022
Third Line TS – Autotransformer T2 & Protection Replacement	2024
Patrick St TS – HV Breaker Replacement	2024
Batchawana TS / Goulais Bay TS – Station Refurbishment	2024
Northern Ave TS – Transformer T1 Replacement	2024
DA Watson TS – Metalclad Switchgear Replacement	2025
Clergue TS – Switchgear Replacement	2026

With the exception of the Sault No. 3 conductor and structure replacement, which is expected to result in significant system reliability benefits, the anticipated facility replacements listed in Table 1 are unlikely to impact other system needs.

3.4 Other Needs and Considerations

The Study Team also identified other needs not captured in the Needs Assessment:

3.4.1 Unbundling of Embedded Generation

There are over 60 MW of solar PV generation facilities embedded in region's LDC service territories (primarily located in the SSM PUC sub-system) that are not visible to the IESO or HOSSM. The historic output of these generation facilities needs to be separated or "unbundled" from the historic demand on the transmission system (i.e., grid demand) to determine the impact of the embedded (or distributed) generation on reducing grid demand and contributing to the reliability of the local transmission system.

3.4.2 Expiration of Generation Contracts

Between 2029 and 2031, over 120 MW of IESO-contracted generation facilities in the SSM PUC sub-system will expire. The impact on regional supply and reliability if these generators do not continue to operate after contract expiry will need to be determined.

3.4.3 Ferrochrome Smelter

In May 2019, a potential industrial customer and the city of Sault Ste. Marie announced their plan to site a ferrochrome production facility in the city, with construction planned to begin in 2025. Depending on the connection configuration of the facility, this project could impact the reliability of the local transmission system and may require regional coordination.

3.5 Analysis of Needs and Planning Approach

3.5.1 Needs to be Addressed in Local Planning

A local planning process is recommended to address the restoration needs identified at Andrew TS, Batchawana TS, Echo River TS and Goulais TS, described in Section 3.3.3, as well as the end-of-life needs described in Section 3.3.4. The Study Team will monitor the sustainment plans for these facilities to ensure they are coordinated with the IRRP.

3.5.2 Needs to be Addressed in Integrated Regional Resource Plan (IRRP)

The remaining needs discussed in Section 3.3:

- Have the potential to be addressed, in whole or part, by non-wires solutions;
- Could be impacted by varying bulk systems flows;
- Could be addressed in a coordinated manner (e.g., one solution may be able to address multiple needs);
- Impact multiple LDCs in the region and
- Require ongoing engagement and coordination with community-level energy planning activities.

As these needs should be addressed in a coordinated manner, the Study Team recommends an IRRP be undertaken for the region.

4 Conclusion

The Scoping Assessment concludes that:

1. A coordinated regional planning approached is required and an IRRP is recommended for the ELS Region to address the:
    - Third Line TS autotransformer overload
    - No. 1 Algoma overload
    - Load security needs described in Section 3.3.3
    - Other needs and considerations described in Section 3.4

    It is important to note that this list of needs is not exhaustive, as further detailed evaluation undertaken through the IRRP may identify new needs, particularly those requiring consideration for the longer term. Additionally, the IRRP process allows for continuous coordination of information related to needs, timing, and potential solutions with the ongoing bulk transmission studies and end-of-life activities in the region.

    The draft Terms of Reference outlining the scope, objectives and timeline of the ELS IRRP can be found in Appendix A.

2. Local planning is recommended to address both the restoration needs identified at Andrew TS, Batchawana TS, Echo River TS and Goulais TS, described in Section 3.3.3, and the end-of-life needs described in Section 3.3.4. The Study Team will monitor the sustainment plans for these facilities to ensure they are coordinated with the IRRP.

List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
ELS	East Lake Superior
EWTW	East West Transfer West
GLPT	Great Lakes Power Transmission
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie LP
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
NUG	Non-Utility Generator
NA	Needs Assessment
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

Appendix A: The East Lake Superior 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) for the East Lake Superior (ELS) region.

Based on the needs identified through the Needs Assessment (NA) process, and further investigation through the Scoping Assessment, the Study Team recommended an integrated regional resource planning approach for the region.

The East Lake Superior Region

The ELS region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically 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.

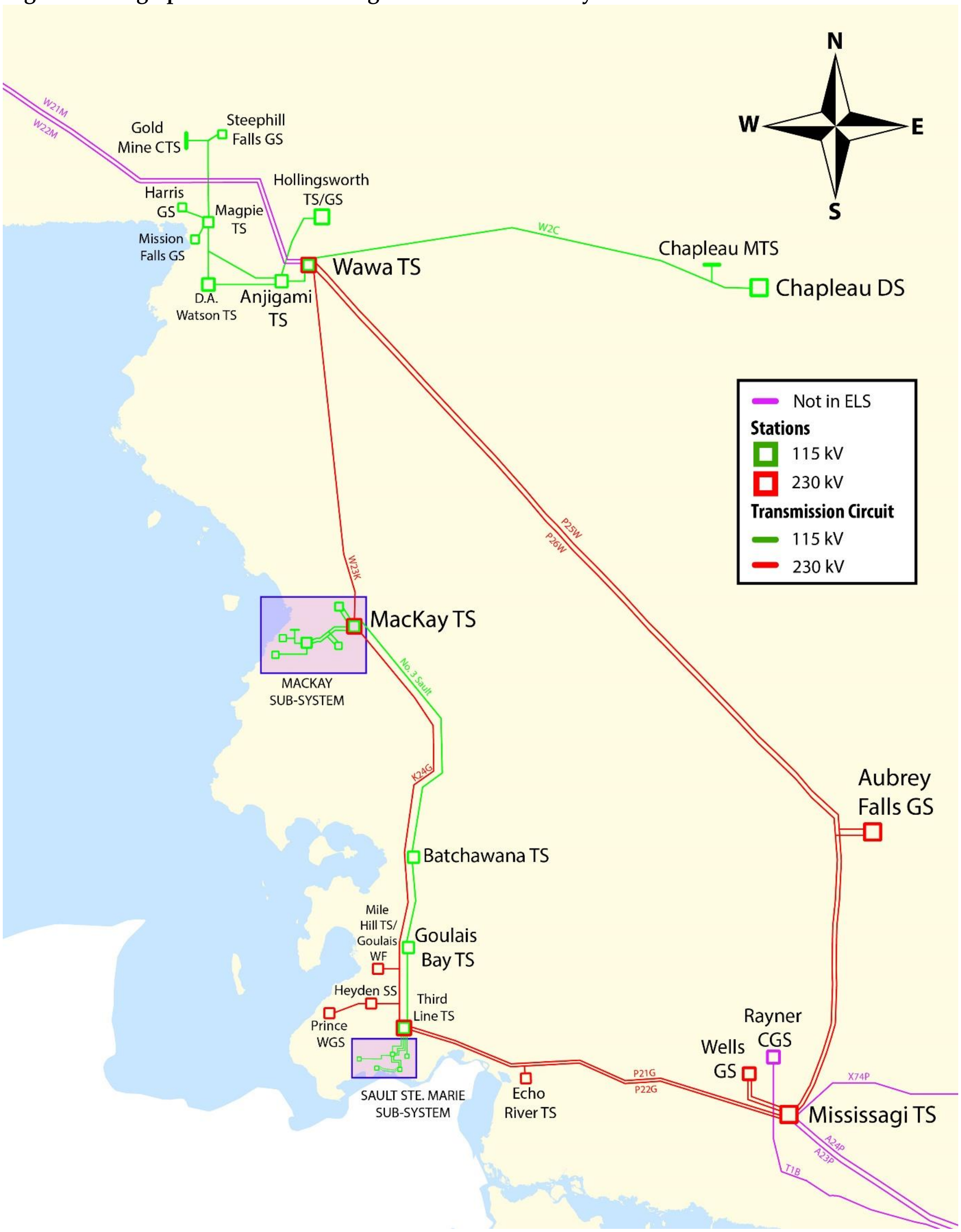
Electrical supply to the region is provided primarily through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both bulk system and regional system functions. That is, in addition to delivering reliable supply to local customers, they also form part of an integrated network that enables the bulk transfer of electricity across the province. Although the bulk transmission system is not the focus of regional planning, it impacts how the system is modelled and studied.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, wind and solar farms and thermal generating facilities. The transmitters in the region are HOSSM and HONI; the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and SSM PUC.

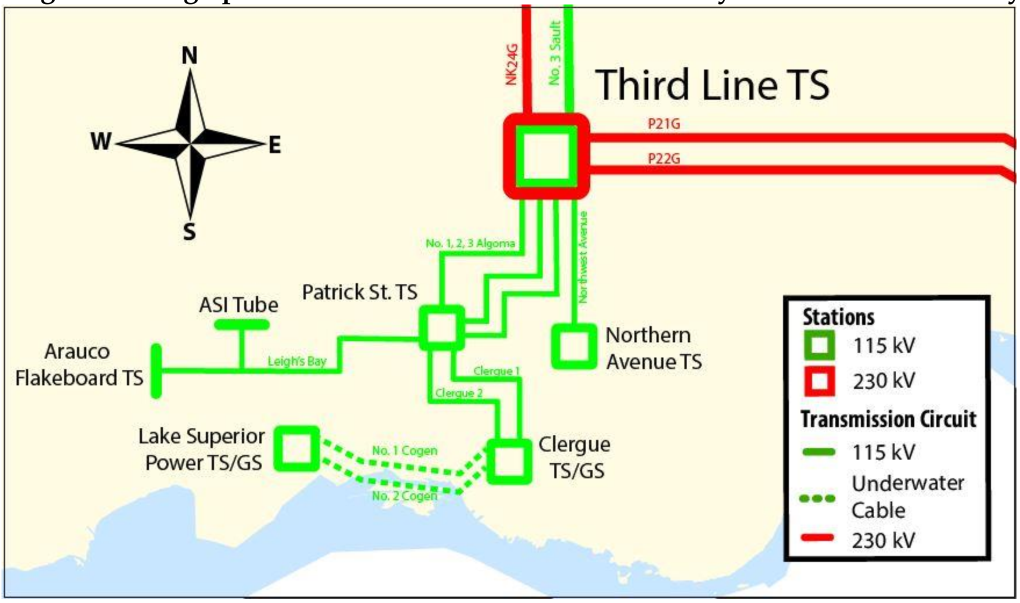
Geographic layouts of the electricity infrastructure supplying the region are shown in Figures 1, 2 and 3. An electrical single line diagram for the same area is shown in Figure 4.

Figure 1: Geographical Area of the Region with Electrical Layout



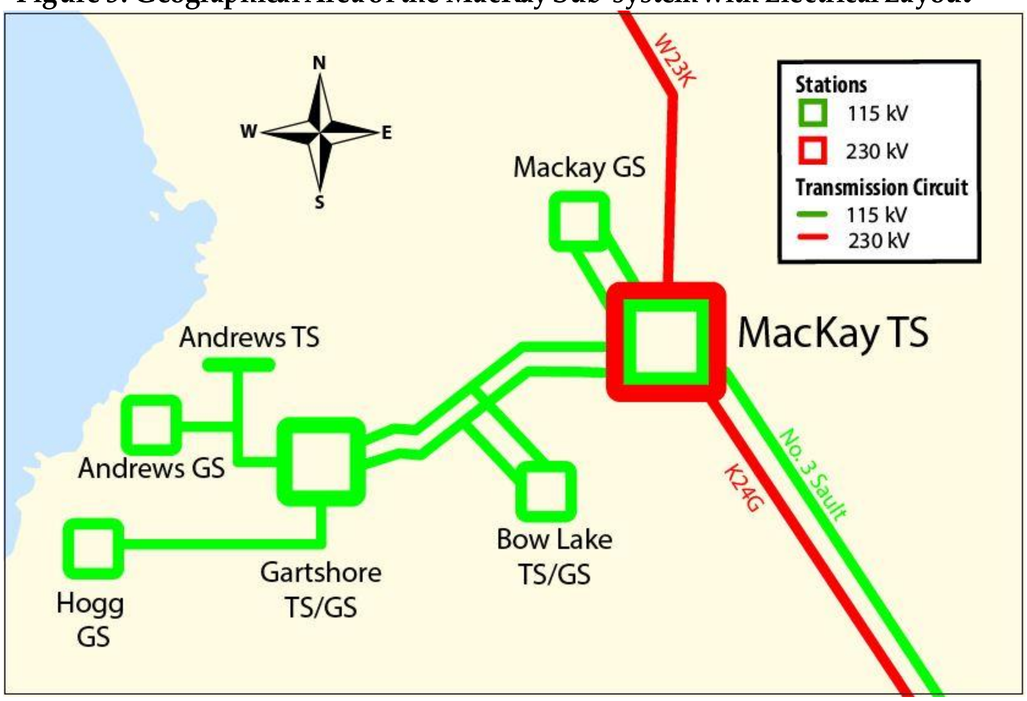
Source: IESO

Figure 2: Geographical Area of the Sault Ste. Marie Sub-system with Electrical Layout



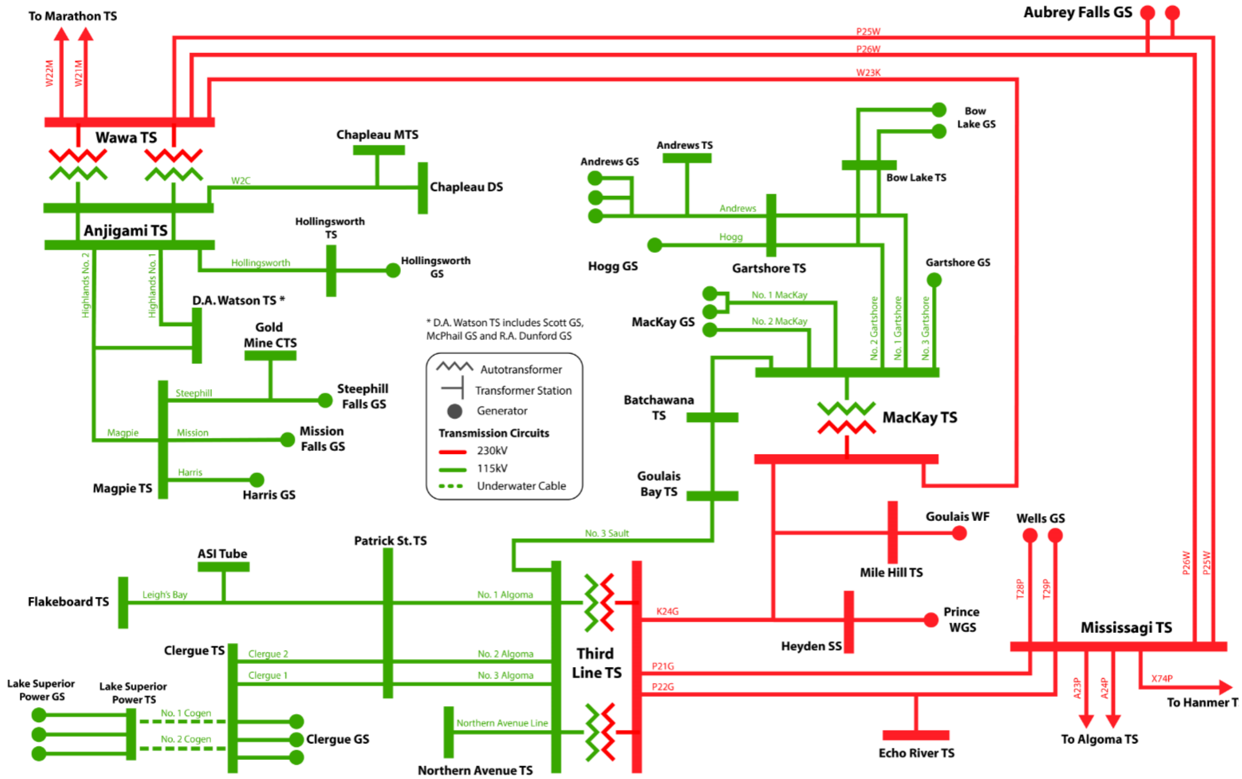
Source: IESO

Figure 3: Geographical Area of the MacKay Sub-system with Electrical Layout



Source: IESO

Figure 4: ELS Region Single Line Diagram



Source: IESO

Background

The first cycle of the ELS regional planning process was initiated by the former Great Lakes Power Transmission (GLPT) in October 2014 and completed in December 2014 with the publication of the 2014 NA report. That report identified a number of potential needs and recommended addressing them through the development of localized wires-only solutions – further coordinated regional planning did not proceed following its release.

In 2016, Hydro One acquired GLPT and renamed the company Hydro One Sault Ste. Marie LP. The second cycle of regional planning was kicked off by HOSSM in April 2019 and the NA report was published in June 2019. The needs identified in this report form the basis of the analysis for the Scoping Assessment and are discussed in further detail in Section 3 of the Scoping Assessment Report.

During the Scoping Assessment, the Study Team reviewed the nature and timing of known needs to determine both the most appropriate planning approach and the best geographic grouping of needs to create efficient study areas. The planning approaches considered include:

1. An IRRP – where a greater range of options, including non-wires, are to be considered as options and/or closer coordination with communities and stakeholders is required;

2. A RIP – which considers more straightforward wires-only options with limited engagement; or
3. A local plan undertaken by the transmitter and affected local distribution companies (LDCs) – where no further regional coordination is needed.

2. Objectives

The East Lake Superior IRRP will assess the adequacy of electricity supply to customers in the region and develop a set of recommendations to reliably maintain supply over the next 20 years. Specifically, the IRRP will:

- Assess the adequacy of electricity supply to customers in the ELS region over the next 20 years;
- Identify system reliability needs and develop and assess options to maintain system reliability;
- 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 with the flexibility to accommodate changes in key assumptions over time, while keeping options viable.

3. Scope

This IRRP will develop and recommend an integrated plan to meet region needs. The plan will be a joint initiative involving HOSSM, HONI, Algoma Power Inc., Hydro One Distribution, Sault Ste. Marie PUC and the IESO. These organizations will be defined as the Working Group for the ELS IRRP.

The plan will focus on:

- Third Line autotransformer overload need
- No.1 Algoma overload need
- Load security needs in the SSM PUC sub-system
- Unbundling of embedded generation
- Any additional needs that emerge in carrying out the IRRP

As with all IRRPs, the ELS IRRP will integrate forecast electricity demand growth, conservation and demand management (CDM); uptake of distributed energy resources (DERs); transmission and distribution system capability; relevant community plans; and bulk system developments as applicable. The IRRP will be carried out in a manner that allows for continuous coordination of information with other planning activities and processes.

The ELS IRRP process will involve:

1. Development of a stakeholder engagement plan.
2. Creation of an updated 20-year demand/load forecast for the region.

3. Assessment of the adequacy and reliability of the transmission system against established criteria and determination of the area's load meeting capability.
    a. Identify or confirm the system needs and adequacy of the area's load meeting capability for the study period using the updated load forecast.
    b. Confirm identified restoration and security needs using the updated load forecast.
    c. Collect information on any known reliability issues and load transfer capabilities from LDCs.
4. Development and assessment of options to mitigate identified needs. Options are evaluated using decision-making criteria, including but not limited to technical feasibility, economics, reliability performance, and environmental and social factors.
5. Development of the long-term recommendations and the implementation plan.
6. Completion of the IRRP report documenting near-, mid-, and long-term needs and recommendations.

Depending on the nature and the urgency of the electricity needs and risks identified, the IRRP could recommend a combination of the following:

- Active monitoring of load growth and equipment performance;
- Project development work to shorten lead times, without firm commitment for constructing the project;
- Commitment of project and proceed with project implementation (e.g., resources acquisition, transmission procurement, regulatory approval);
- Interim measures to manage near-term requirements, pending implantation of longer-term solutions;
- Pilots, studies and/or engagement to gather more information; and
- Coordination with other planning or related processes (e.g., community or bulk system planning).

Should the need for infrastructure investment be identified, the IRRP will provide a rationale and define high-level requirements to support project development and implementation to be carried out by other proponents. The outcomes from the ELS IRRP will help inform transmitter and LDC rate filings and any related transmission/resource acquisition processes that may result.

It is important to note that detailed discussion of acquisition mechanisms, cost allocation, cost recovery, siting, operations and implementation of recommended projects are beyond the scope of an IRRP.

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

4. Data and Assumptions

The plan may consider the following data and assumptions, where applicable:

- Demand data

    - Historical coincident and non-coincident peak demand information for the region
    - Impact of embedded generation on historic grid demand
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios, e.g., by region, sub-system, TS
    - Coincident peak demand data, including transmission-connected customers
    - Potential future load customers
- Conservation and demand management
    - Long-term conservation forecast for LDC customers based on planned provincial CDM activities
    - LDC programs, if applicable
    - Conservation potential studies, if available
- Local resources
    - Existing local generation, including distributed generation, district energy, customer-based generation, non-utility generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future resource proposals as relevant
- Relevant local plans, as applicable
    - LDC distribution system plans
    - Community energy plans and municipal energy plans (e.g., Community Energy Investment Strategy for Waterloo Region)
    - Municipal growth plans
- Criteria, codes and other requirements
    - ORTAC
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - Transformer ratings as per asset owner(s)
    - Load transfer capabilities
    - Technical and operating characteristics of local generation
- End-of-life asset considerations and sustainment plans
    - Transmission assets
    - Distribution assets
    - Impact of ongoing plans and projects on applicable facility ratings
- Other considerations, as applicable

5. Working Group

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

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Sault Ste. Marie LP
- Hydro One Networks Inc.
- Algoma Power Inc.
- Hydro One Distribution
- Sault Ste. Marie PUC

<u>Authority and Funding</u>

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

5. Engagement

Integrating early and sustained engagement with communities and stakeholders is a key component of the IRRP planning process.

The first step in engagement will consist of the development of a stakeholder engagement plan, which will be made available for comment before it is finalized. The scope of community and stakeholder engagement to be considered for this IRRP may include:

- Local electricity needs and considerations
- Status and key assumptions from community energy planning (e.g., energy intensity, electric vehicles and fuel switching scenarios)
- Status and key assumptions in growth plans and local economic developments (e.g., housing, population growth, commercial and industrial development)
- Impact of climate change in the East Lake Superior region
- Long-term land use and Infrastructure corridor plans
- Local interest in developing and implementing community-based energy solutions and factors that could facilitate or hinder the implementation of community-based energy solutions (e.g., existing or planned pilot projects, and the availability of local funding to support them; local policy/programs that enable/hinder project development; support from local utilities, community groups and government; and land use impacts and considerations.

6. Activities, Timeline and Primary Accountability

Table A-1: Summary of Expected IRRP Timelines and Activities

	Activity	Lead Responsibility	Deliverable(s)	Approximate Time frame
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	July - Oct 2019
2	**Develop the Planning Forecast for the sub-region**			
	Establish historical coincident and non-coincident peak demand information	*IESO*	- Long-term planning forecast scenarios	Oct 2019 – Jan 2020
	Establish historical weather correction, median and extreme conditions	*IESO*		
	Establish gross peak demand forecast and growth scenarios	*LDCs*		
	Establish existing, committed and potential distributed generation	*LDCs*		
	Establish near- and long-term conservation forecasts based on planned energy-efficiency activities and codes and standards	*IESO*		
	Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Oct 2019 – Jan 2020
4	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	- Relevant community plans	Oct 2019 – Jan 2020

<table>
<tr><th colspan="2">Activity</th><th>Lead Responsibility</th><th>Deliverable(s)</th><th>Approximate Time frame</th></tr>
<tr><td>5</td><td>Complete system studies to identify needs over a 20-year period
- Develop PSS/E base cases, including bulk system configuration and connectivity assumptions as identified in the key assumptions
- Apply reliability criteria – as defined by NERC and NPCC and described in ORTAC – to demand forecast scenarios
- Confirm and refine the need(s) and timing/magnitude</td><td>IESO</td><td>- Summary of needs based on demand forecast scenarios for the 20-year planning horizon</td><td>Q1 – Q2 2020</td></tr>
<tr><td rowspan="8">6</td><td>Develop Options and Alternatives</td><td></td><td></td><td></td></tr>
<tr><td>Develop conservation options, where applicable</td><td>IESO and LDCs</td><td rowspan="7">- Develop flexible planning options for forecast scenarios</td><td rowspan="7">Q2 – Q3 2020</td></tr>
<tr><td>Develop local generation options, where applicable</td><td>IESO and LDCs</td></tr>
<tr><td>Develop transmission (see Action 7 below) and distribution options, where applicable</td><td>All</td></tr>
<tr><td>Develop options involving other electricity initiatives, where applicable (e.g., smart grid, storage)</td><td>IESO/ LDCs with support as needed</td></tr>
<tr><td>Integrate with bulk needs</td><td>IESO</td></tr>
<tr><td>Develop portfolios of integrated alternatives, where applicable</td><td>All</td></tr>
<tr><td>Technical comparison and evaluation</td><td>All</td></tr>
<tr><td rowspan="5">7</td><td>Plan and Undertake Community & Stakeholder Engagement</td><td></td><td></td><td></td></tr>
<tr><td>Early engagement with local municipalities and Indigenous communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario</td><td>All</td><td rowspan="4">- Community and stakeholder engagement plan
- Input from local communities</td><td>Q3 2020</td></tr>
<tr><td>Develop communications materials</td><td>All</td><td rowspan="3">ongoing</td></tr>
<tr><td>Undertake community and stakeholder engagement</td><td>All</td></tr>
<tr><td>Summarize input and incorporate feedback</td><td>All</td></tr>
</table>

	Activity	Lead Responsibility	Deliverable(s)	Approximate Time frame
8	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3-Q4 2020
9	**Prepare the IRRP report detailing the recommended near-, medium- and long-term plan for approval by all parties**	*IESO*	- IRRP report	March 31 2021

Appendix B: Selecting a Regional Planning Approach

Needs identified through the NA process will be reviewed during the Scoping Assessment to determine whether a Local Plan (LP), Regional Infrastructure Plan (RIP), or Integrated Regional Resource Plan (IRRP) is more appropriate. Where multiple sub-regions are identified, each will be considered individually. A combination of LP, RIP and IRRP planning approaches could be selected in different sub-regions, although an urgent need for wires-type solution will typically trigger a hand-off letter instead.

Each of the three potential planning outcomes has different functions, and selection should be made based on a region's unique needs and circumstances. The criteria used to select the regional planning approach within each sub-region are consistent with the principles laid out in the PPWG 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, including conservation, generation, new technologies and wires infrastructure, to determine the optimal mix of resources to meet region needs over a 20-year time frame. RIPs are narrower in scope, focusing instead on identifying and assessing specific wires alternatives and recommending the preferred wires solution. In limiting the extent of its consideration to wires solutions that do not require further coordinated planning, LPs have the narrowest scope. An LP process is recommended when needs:

a) Are local in nature (only affecting one LDC or customer)
b) Involve limited investments of wires (transmission or distribution) solutions
c) Do not require upstream transmission investments
d) Do not require plan level community and/or stakeholder engagement and
e) Do not require other approvals such as an OEB Leave to Construct (S92) application or Environmental Approvals.

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

---

[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

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

If the only feasible measures involve new/upgraded transmission and/or distribution infrastructure, with no requirement for engagement or anticipated impact on bulk systems, an 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

Determining the feasibility of non-wires alternatives to meet identified needs should also consider issues such as timelines for implementing solutions. For instance, if a need has been identified as immediate or near-term, non-wires solutions that rely on lengthy development and roll-out periods may not be feasible.