Northwest Scoping Assessment Outcome Report

January 13, 2021

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Powering Tomorrow.

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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 Northwest. 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.

In the Northwest, the first cycle of the regional planning divided the region into four sub-regions each with their own Integrated Regional Resource Plan (IRRP) published between Jan 2015 and Dec 2016. These sub-regions include Greenstone-Marathon, North of Dryden, Thunder Bay and West of Thunder Bay. The first cycle concluded in June 2017 with the publication of the Regional Infrastructure Plan (RIP).

The current cycle of regional planning for the Northwest started in March 2020. The Needs Assessment (NA) is the first step in the regional planning process and was carried out by the Study Team led by Hydro One Networks Inc. (Hydro One). This report was finalized on July 17, 2020 and flagged a number of 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 Study Team reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach to address them. The assessment determined the best geographic grouping of the needs to efficiently carry out the study. It also considered past and ongoing initiatives in the region.

This Scoping Assessment Outcome Report recommends a single IRRP for the Northwest 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 study team.
- 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 update 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. Study Team

The Scoping Assessment was carried out with the following participants:

Independent Electricity System Operator (IESO)

Hydro One Networks Inc. (Hydro One Transmission)

Hydro One Networks Inc. (Hydro One Distribution)

Atikokan Hydro Inc.

Fort Frances Power Corporation

Sioux Lookout Hydro Inc.

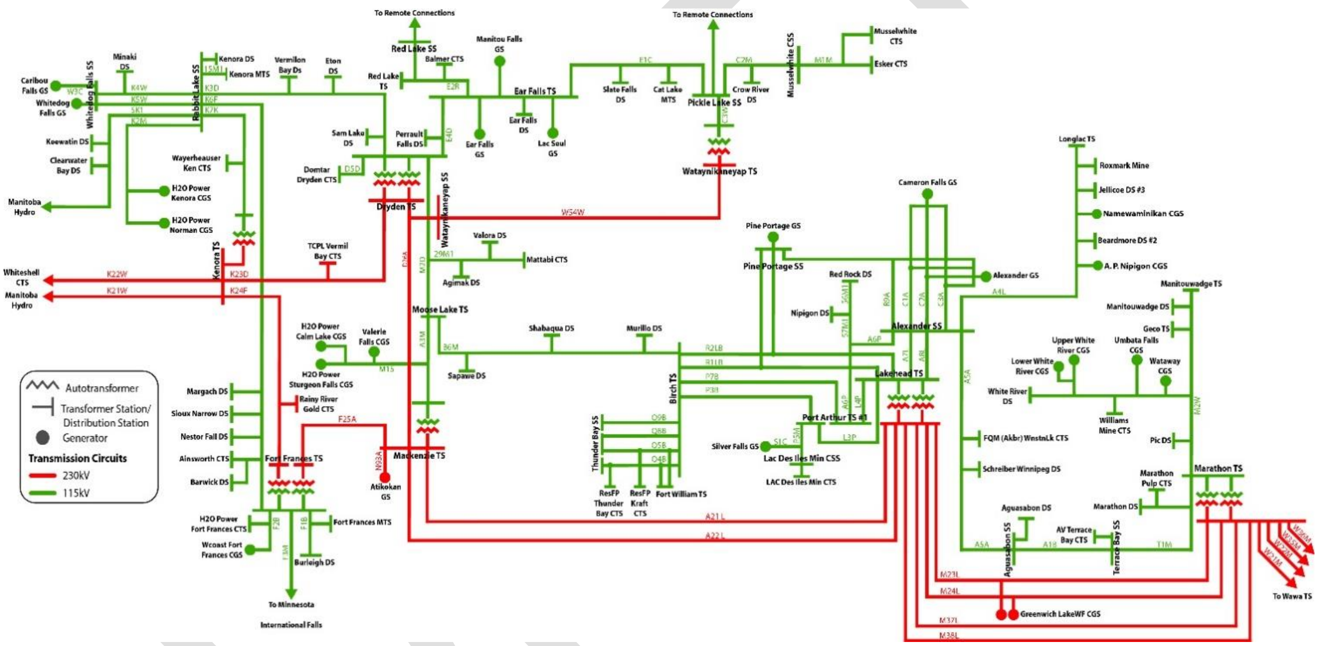
Synergy North

3. Overview of Region and Background

The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River and Thunder Bay.

Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region encompasses the 230 kV circuits from the Manitoba interties in the west to Marathon TS in the east as well as the 115 kV sub-systems in between. The single line diagram of the electrical infrastructure in the region is shown in Figure 3-1.

Figure 3-1 | Electricity Infrastructure in the Northwest Ontario Region



The Northwest region encompasses a vast geographic area and a diversity of economic and social factors unique within Ontario. Planning in this region possesses uncertainties and challenges not normally seen in other parts of the province. Demand in this region is largely driven by resource based industrial customers such as mines and forestry operations. Their development is highly dependent on factors such as commodity prices and access to financing.

In addition to the cities and towns, the Northwest has many rural and remote communities often served from long single-supply transmission circuits. The municipalities within the Northwest region includes the Town of Marathon, Municipality of Greenstone, Township of Nipigon, Township of Manitowadge, Township of Schreiber, Township of Terrace Bay, Township of White River, City of Thunder Bay, Township of Red Rock, Township of Nipigon, Municipality of Neebing, Municipality of Oliver Paipoonge, Municipality of Shuniah, Township of O'Connor, Township of Conmee, Township of Dorion, Township of Gillies, Township of Alberton, Town of Atikokan, Township of Chapple, Township of Dawson, Township of Emo, Town of Fort Frances, Township of Lake of the Woods, Township of La Vallee, Township of Morley, Town of Rainy River, City of Dryden, City of Kenora, Municipality of Machin, Municipality of Sioux Lookout, Township of Ignace, and Township of Sioux Narrows-Nestor Falls.

The Northwest Ontario region is home to about half of the First Nation communities in the province as shown in Table 3-1. A number of Métis communities are also located in the Northwest region. The following are affiliated with the Métis Nation of Ontario: Atikokan and Area Metis Council, Greenstone Métis Council, Kenora Metis Council, Superior North Shore Métis Council, Northwest Métis Council, Sunset Country Metis Council and Thunder Bay Métis Council. Red Sky Métis Independent Nation is another Métis community with its office located in Thunder Bay. Note that not all First Nation and Métis communities listed are grid connected.

Table 3-1 | List of First Nation Communities in the Northwest Region

First Nation Communities	
Animbiigoo Zaagi'igan Anishinaabek	Naicatchewenin
Animakee Wa Zhing #37	Namaygoosisagagun
Anishinaabeg of Naongashing	Naotkamegwanning
Anishnawbe of Wauzhushk Onigum	Neskantaga
Aroland	Nigigoonsiminikaaning Nation
Bearskin Lake	Niisachewan
Big Grassy	North Caribou Lake
Biinjitiwaabik Zaaging Anishinaabek	North Spirit Lake
Bingwi Neyaashi Anishinaabek	Northwest Angle No. 33
Cat Lake	Obashkaandagaang
Constance Lake	Ojibway Nation of Saugeen
Couchiching	Ojibways of Onigaming
Deer Lake	Ojibways of Pic River
Eabametoong	Pays Plat
Eagle Lake	Pic Mobert
Fort William	Pikangikum
Ginoogaming	Poplar Hill
Grassy Narrows	Rainy River
Gull Bay	Red Rock Indian Band

First Nation Communities

Iskatewizaagegan Independent	Sachigo Lake
Kasabonika Lake	Sandy Lake
Keewaywin	Seine River
Kingfisher Lake	Shoal Lake No.40
Kitchenuhmaykoosib Inninuwug	Slate Falls
Lac Des Mille Lacs	Wabaseemoong Independent Nation
Lac La Croix	Wabauskang
Lac Seul	Wabigoon Lake Ojibway Nation
Long Lake No. 58	Wapekeka
Marten Falls	Wawakapewin
McDowell Lake	Webequie
Mishkeegogamang	Whitesand
Mitaanjigaming	Wunnumin Lake
Muskrat Dam Lake	

3.1 Previous Regional Planning Cycle & Status Update

The previous Northwest Scoping Assessment Outcome Report was published in January 2015 and recommended four sub-regions each with their own IRRP:

- Greenstone-Marathon (published June 2016)
- Thunder Bay (published December 2016)
- West of Thunder Bay (published July 2016)
- North of Dryden (already underway at the time of the Scoping Assessment; published January 2015)

Each IRRP is briefly summarized below.

Greenstone-Marathon IRRP

The Greenstone-Marathon sub-region is located northeast of Thunder Bay and is electrically supplied from Marathon TS and Alexander SS. The recommendations for system enhancements were heavily dependent on two industrial customers – a Geraldton area mine and the Energy East Pipeline. Since the IRRP was published, neither industrial customers have connected to the system and, as such, no system enhancements were needed.

The 2020 Needs Assessment identified higher than previously forecast load distribution connected load growth which could cause capacity needs in the area and warrants further investigation in the current regional planning cycle.

Thunder Bay IRRP

Thunder Bay sub-region consists of the 115 kV network supplied from Lakehead TS (except A4L which is included in the Greenstone-Marathon IRRP). No enhancement was necessary under the low and medium demand forecast scenarios. The high demand forecast scenario showed that system enhancements may be necessary. To supply the high demand scenario, the IRRP identified potential options including new autotransformers at Lakehead TS or Birch TS and local generation. Additionally, the IRRP recommended further investment at Port Author TS if demand growth materialized.

The 2020 Needs Assessment noted that refurbishment work scheduled for 2025 at Port Author TS would increase the station capacity. The Needs Assessment also identified higher than anticipated growth in the area, in excess of the previous IRRP's high scenario, which could introduce additional capacity needs.

West of Thunder Bay IRRP

The West of Thunder Bay sub-region is comprised of the diamond-shaped 230 kV system from Mackenzie TS to Kenora TS as well as the surrounding 115 kV sub-systems (Kenora 115 kV, Dryden 115 kV, Moose Lake 115 kV, Fort Frances 115 kV). No enhancements were necessary under the low and reference demand forecast scenarios. The high demand forecast scenario showed that Dryden 115 kV sub-system reinforcements may be necessary. The IRRP identified local generation and additional autotransformers as potential options should load growth materialize.

While the 2020 Needs Assessment did not specifically identify any new capacity needs in this area, a refresh of the high scenario and associated options is warranted.

North of Dryden IRRP

The North of Dryden sub-region is comprised of the 115 kV system north of Dryden TS supplied by E4D circuit. The IRRP identified that the sub-region was at capacity and new infrastructure was needed to supply forecast growth and remote connections. The IRRP findings supported the 230 kV single circuit to Pickle Lake option (also known as the Wataynikaneyap or Watay Project) which was previously identified as a priority project in the 2010 and 2013 Long-Term Energy Plan. A subsequent 2016 letter from the IESO to the OEB outlined the recommended scope of the new line to Pickle Lake and Remote Connections Project. Implementation of the Wataynikaneyap Project (further described in Section 3.2) started shortly thereafter and is now near completion. The 2020 Needs Assessment found that the new Watay project provides relief to the E1C circuit and Red Lake sub-system capacity needs. Nevertheless, this area continues to have the potential for high mining-related load growth and warrants further study in the current regional planning cycle.

3.2 Major Transmission System Reinforcements

Two new transmission system projects, the East-West Tie ("EWT") reinforcement and Wataynikaneyap Transmission Project ("Watay Project"), discussed above, are nearing completion. These projects are assumed to be in service for the purpose of the current regional planning cycle. The EWT reinforcement adds four new 230 kV circuits: M37L and M38L from Lakehead TS to Marathon TS and W35M and W36M from Marathon TS to Wawa TS. The Watay Project includes a new 230 kV circuit between Watay 230/115 kV TS and Dinorwic Jct on circuit D26A. Ten remote First Nation communities north of Pickle Lake will be electrically supplied by Watay TS. An additional six remote First Nation communities north of Red Lake are electrically supplied by a switching station that taps onto the circuit E2R adjacent to Balmer Jct.

Development work is currently underway for the Waasigan Transmission Line which is another potential transmission system reinforcement between Thunder Bay to Atikokan and from Atikokan to Dryden to address potential bulk system needs. The IESO continues to monitor the needs in this area and, as such, a commitment to construct the line has not been made. For this reason, the Waasigan Transmission Line is not assumed to be in service for the purpose of this regional planning cycle. In addition, the need and timing of bulk system reinforcements are not included in the scope of regional planning. This is further discussed in Section 5.

4. Summary of New and Updated Needs

The first phase of the current regional planning cycle, the Hydro One-led Needs Assessment, was completed in July 2020.

This section briefly summarizes the new and updated needs identified in the Needs Assessment report. Please refer to the full Needs Assessment report for more details. The system capacity, station capacity, load security/restoration, and end of life needs are described in the following subsections. Note that this section documents all identified needs regardless of whether or not further regional coordination is warranted. Section 5 specifies the planning approach and outlines the specific needs that will be in scope for subsequent regional planning stages.

4.1 System Capacity Needs

System capacity (or "load meeting capability") refers to the ability of the electricity system to supply power to customers in the area either by generating the power locally or bringing it in through the transmission system. System capacity needs were identified in the Needs Assessment report for the Thunder Bay Area and the Marathon Area as described in Table 4-1.

Table 4-1 | System Capacity Needs

Need #	Station/Circuit	Description of Need
1	Lakehead TS, A5A, A1B,T1M	Voltage support will be required to prevent voltage collapse for loss of both Lakehead TS autotransformers. Mitigation is required to prevent overloading of circuits A5A, A1B, and T1M under this outage condition. The Needs Assessment recommended further studies in subsequent stages of regional planning.
2	Marathon TS, A5A	Voltage support will be required to prevent voltage collapse for the loss of both Marathon TS autotransformers. Mitigation is required to prevent overloading of circuit A5A under this outage condition. The Needs Assessment recommended further studies in subsequent stages of regional planning.

4.2 Station Capacity Needs

Station capacity refers to the ability to convert power from the transmission system down to distribution system voltages. Station capacity needs were identified at Kenora MTS, Sapawe DS, and Sam Lake DS as described in Table 4-2.

Table 4-2 | Station Capacity Needs

Station	Assessment
Kenora MTS	Kenora MTS is expected to reach capacity by 2027. The Needs Assessment recommended local planning to address this need. This Scoping Assessment revisited this need and will include it in scope for further evaluation in regional planning. Please see Section 5.2 for more details.
Sapawe DS	Load growth at Sapawe DS is expected to reach the Winter and Summer Planned Loading Limit by 2028 and 2026 respectively. The Needs Assessment recommended distribution planning to address this need.
Sam Lake DS	Sam Lake DS is already at capacity. Due to the significant load increase, additional voltage support will also be required at this station. The Needs Assessment recommended that Sioux Lookout Hydro, Hydro One Distribution and Hydro One Transmission collaborate to address this need in local planning.

4.3 Load Security and Restoration Needs

Load security describes the total amount of load interrupted following major transmission outages. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes.

The Needs Assessment did not identify any load security or load restoration needs. The Northwest region has many 115 kV radial circuits and / or single transformer connected stations where loss of load is anticipated after a single contingency. The magnitude of load interrupted is within the allowable limits and the load restoration criteria is met since the standards allow for leeway in remote locations. Nevertheless, outages have high socio-economic costs for impacted communities and, so, the Needs Assessment recommended that load restoration be further investigated in subsequent stages of regional planning. Alleviating this impact with additional system investments can often be cost prohibitive unless they can be integrated with solutions designed to meet needs driven by criteria violations. Impacted radial circuits include but not limited to:

- 115 kV A4L (Alexander SS x Longlac TS)
- 115 kV M2W (Marathon TS x White River DS)
- 115 kV E2R (Ear Falls TS x Red Lake TS)
- 115 kV C2M (Pickle Lake SS x Musselwhite CSS)
- 115 kV K3D (Sam Lake DS x Dryden TS)
- 115 kV 29M1 (Ignace Jct x Mattabi CTS)
- 115 kV M1S (Moose Lake TS x Crilly DS)
- 115 kV A6P/56M1/57M1 (Alexander SS x Port Arthur TS x Red Rock DS)
- 115 kV P5M/S1C (Port Arthur TS x Lac Des Iles Mine CTS)

4.4 End of Life Needs

The Needs Assessment identified numerous facilities approaching end of life over the next 10 years as described in Table 4-3 and 4-4. Replacements for these facilities can be like-for-like, right-sized, or retired depending on system needs. The Needs Assessment recommended coordination with the IESO when required and where feasible.

Table 4-3 | End of Life Circuit Equipment

Station/ Circuit	Timing	Details
A4L	2025	Refurbishment of Beardmore Jct x Longlac TS section.
E1C	2025	Ear Falls TS x Slate Falls DS section and Etruscan Jct x Crow River DS section have been prescribed for line refurbishment.

Table 4-4 | End of Life Station Equipment

Station/ Circuit	Timing	Details
Alexander SS	2022	Existing HV breaker and line switches have reached EOL
Ear Falls TS	2022	Existing HV breaker at the station is reaching EOL
Fort Frances TS	2027	The two (2) 230/115 kV step-down auto-transformer and 115 kV breakers at the station are reaching EOL
Kenora TS	2025	The existing step-down auto-transformer, as well as HV breakers and switches are reaching EOL
Lakehead TS	2025	The existing HV breakers, switches, and Protection & control facilities at the station are approaching EOL
Mackenzie TS	2024	The existing 230/115 kV auto-transformer, as well as HV breakers and line disconnect switches are near EOL
Marathon TS	2024	The existing HV breakers at this station is approaching EOL
Moose Lake TS	2024	The existing two (2) 115/44kV Step-Down Transformer and LV breakers are near EOL

Station/ Circuit	Timing	Details
Port Arthur TS #1	2025	Due to equipment limitations and EOL assets on the LV side of the station, the station has been limited to provide up to 55MW. Once the LV yard refurbishment is complete in 2025, the station capacity will increase to 59MW
Rabbit Lake SS	2022 2024	New HV load break switch installs are due for completion in 2022, while the existing HV breaker / disconnect switches, and line disconnect switches are also near EOL and plans are in place to replace them by 2024
Whitedog Falls SS	2023	The existing 115 kV breakers, and line disconnect switches at the station are near EOL

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 Northwest 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 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 PPWG Report to the Board[1], 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.

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:

[1] 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 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

Whereas the previous regional planning cycle divided the region into 4 sub-regions, this Scoping Assessment recommends a single IRRP that covers the entire Northwest region but focuses on specific issues highlighted in this section.

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, need/timing of the Waasigan Project, and intertie capability with Manitoba/Minnesota. 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.

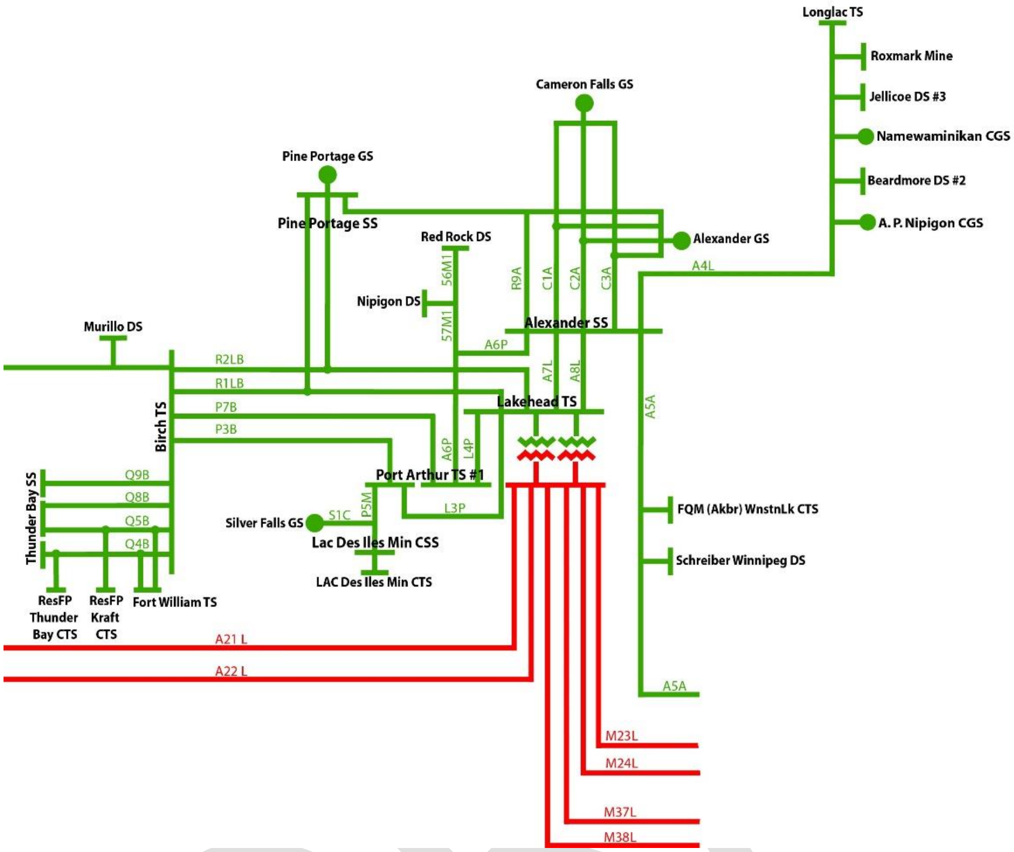
The IRRP will focus on the needs described below.

Thunder Bay Area Capacity Need

The Needs Assessment identified a potential capacity need at Lakehead TS and downstream 115 kV system. Specifically, voltage collapse and overloading on A5A were identified under a N-1-1 contingency where both autotransformers are out of service. Lakehead TS is the primary supply point for the City of Thunder Bay and surrounding area. A single line diagram of the area is show in Figure 5-1.

The IRRP will further study drivers of load growth and the timing of the need. This area has significant hydro generation which will be further studied to update the dependable generation assumption.

Figure 5-1| Single Line Diagram of the Thunder Bay Area

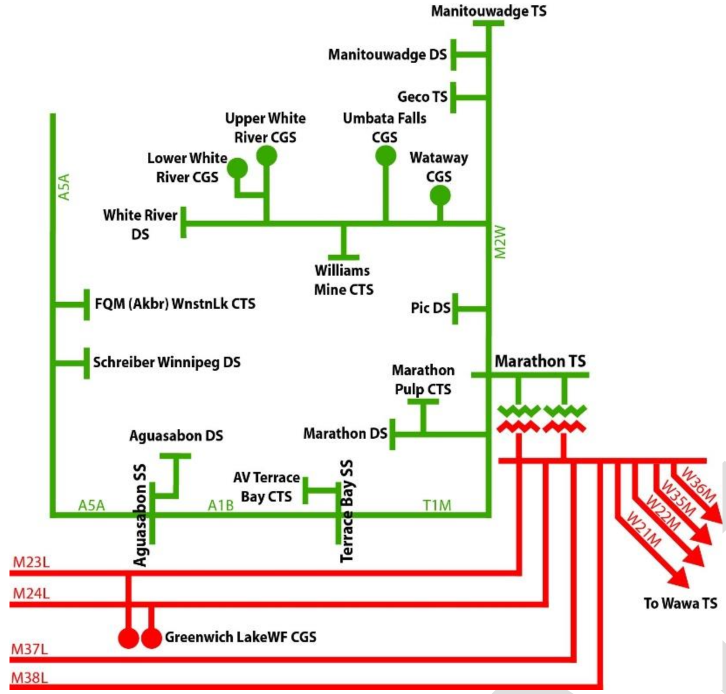


Marathon Area Capacity Need

The Need Assessment identified a potential capacity need at Marathon TS and downstream 115 kV system. Similar to the Thunder Bay capacity need, voltage collapse and thermal overload on A5A were identified. Marathon TS supplies the Town of Marathon, Manitouwadge in the north, White River in the east, and communities on the north shore of Lake Superior. A single line diagram of the area is show in Figure 5-2.

The IRRP will further study drivers of load growth and the timing of the need. As with the Thunder Bay area, there is significant hydro generation which will be further studied to update the dependable generation assumptions.

Figure 5-2| Single Line Diagram of the Marathon Area

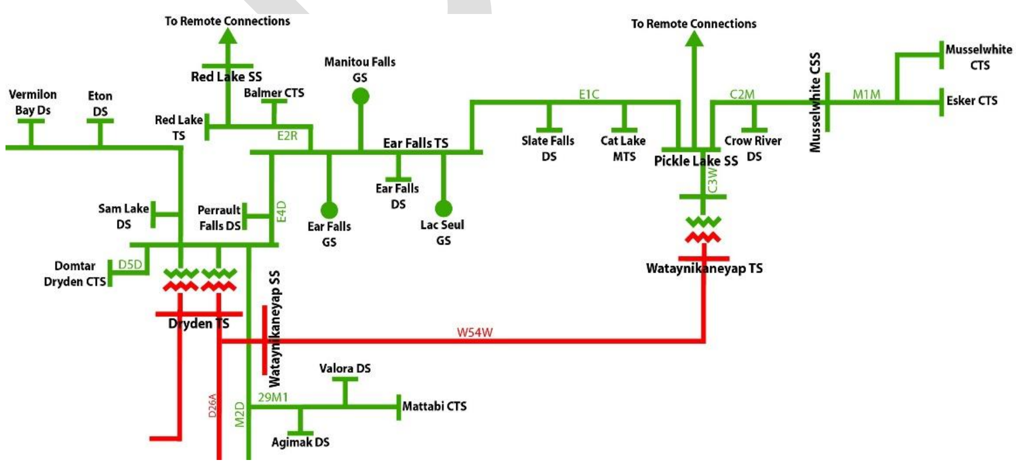


Refresh North of Dryden Area System Capability

The Dryden area includes Dryden TS, the 230 kV system north of Dinorwic Jct, and the 115 kV system served from these two supply points. A single line diagram of the area is shown in Figure 5-3. Although no needs were flagged for this area in the Needs Assessment, there have been significant system topology changes (Wataynikaneyap Project and remote connections) since the last regional planning cycle. This area also has a high concentration of mining developments which contributes to a high degree of uncertainty in the load forecast.

The IRRP will refresh previous studies to assess the capability of the existing system and study potential options to be triggered if future needs materialize.

Figure 5-3| Single Line Diagram of the Dryden Area



Non-Wires Alternatives for Kenora MTS Capacity Need

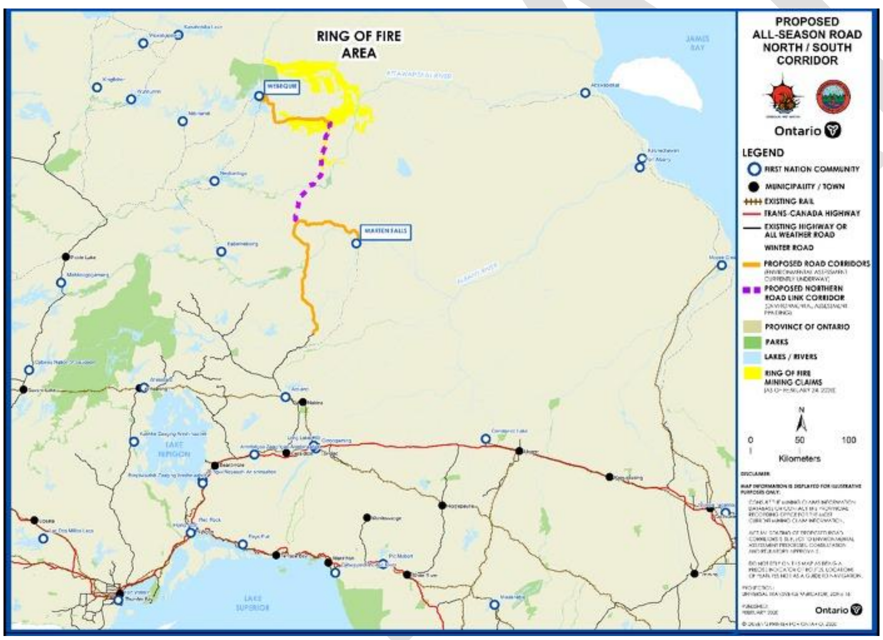
Kenora MTS serves the City of Kenora and is expected to reach capacity around 2027. The Needs Assessment originally recommended that this need be addressed through local planning but, upon further examination, the timing of the need and the rate of growth at Kenora MTS suggests non-wires alternatives may be possible.

The IRRP will perform a preliminary assessment to determine if non-wires options are feasible from a cost, reliability and implementation perspective. If not, local planning between Synergy North and Hydro One will continue to develop a station expansion/modification solution as recommended in the Needs Assessment.

Ring of Fire Connection Scenario

The Ontario provincial government's agreement to support the Northern Road Link puts renewed focus on Ring of Fire developments. A map of the proposed road is show in Figure 5-4. The IRRP will assess the capability of the local electricity system to accommodate new load at the Ring of Fire. Note that, if warranted, the development of a specific connection plan will likely be addressed in a separate study following the IRRP.

Figure 5-4 | Proposed All-Season Road (Source: Government of Ontario)



Load Restoration

As stated in the Needs Assessment, the Northwest region has many radial single circuit supplied load stations. These stations are not in violation of load restoration criteria since the standards allow for leeway given their remote location. Nevertheless, outages have high socio-economic costs for impacted communities and traditional wires solutions are often cost prohibitive. Given the high degree of stakeholder interest, the IRRP will investigate opportunities for incremental improvements (including non-wires solutions) where there is the potential for integration with other system needs and where cost effective. This is consistent with the IESO's Customer Reliability Review[2] completed in 2019.

End of Life

The Needs Assessment identified numerous facilities nearing end of life over the next 10 years. The majority of these anticipated facility replacements are minor and do not have the potential to impact other system needs. However, there are several more significant facilities nearing end of life including step-down transformers at Moose Lake TS, autotransformers at Fort Frances TS, Kenora TS, and Mackenzie TS as well as segments of A4L and E1C. The IRRP will, where feasible within the timelines afforded by each project, examine opportunities to align the replacement of these facilities with other regional needs.

[2] http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Customer-Reliability-Review

6. Conclusion and Next Steps

This Scoping Assessment concludes that a single IRRP covering the entire region will be undertaken to address the following items as discussed according to Section 5.2:

- Thunder Bay Area Capacity Need
- Marathon Area Capacity Need
- Refresh North of Dryden Area System Capability
- Non-Wires Alternatives for Kenora MTS Capacity Need
- Ring of Fire Connection Scenario
- Load Restoration
- End of Life

Note that this list is not exhaustive. 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. In particular, the load forecast from the IRRP will be leveraged to better understand the drivers of load growth and further refine the need date for the Waasigan Transmission Line. The draft Terms of Reference for the Northwest IRRP can be found in Appendix 2.

Furthermore, this Scoping Assessment concurs with the Needs Assessment recommendation to address the Sapawee DS and Sam Lake DS capacity needs through distribution and local planning, respectively.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CTS	Customer Transformer Station
DER	Distributed Energy Resources
DG	Distributed Generation
DS	Distribution Station
EWT	East-West Tie
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
kV	kilovolt
LDC	Local Distribution Company
LP	Local Plan
MTS	Municipal Transformer Station
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
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SS	Switching Station
TS	Transformer Station

Appendix 2 – Northwest IRRP Terms of Reference

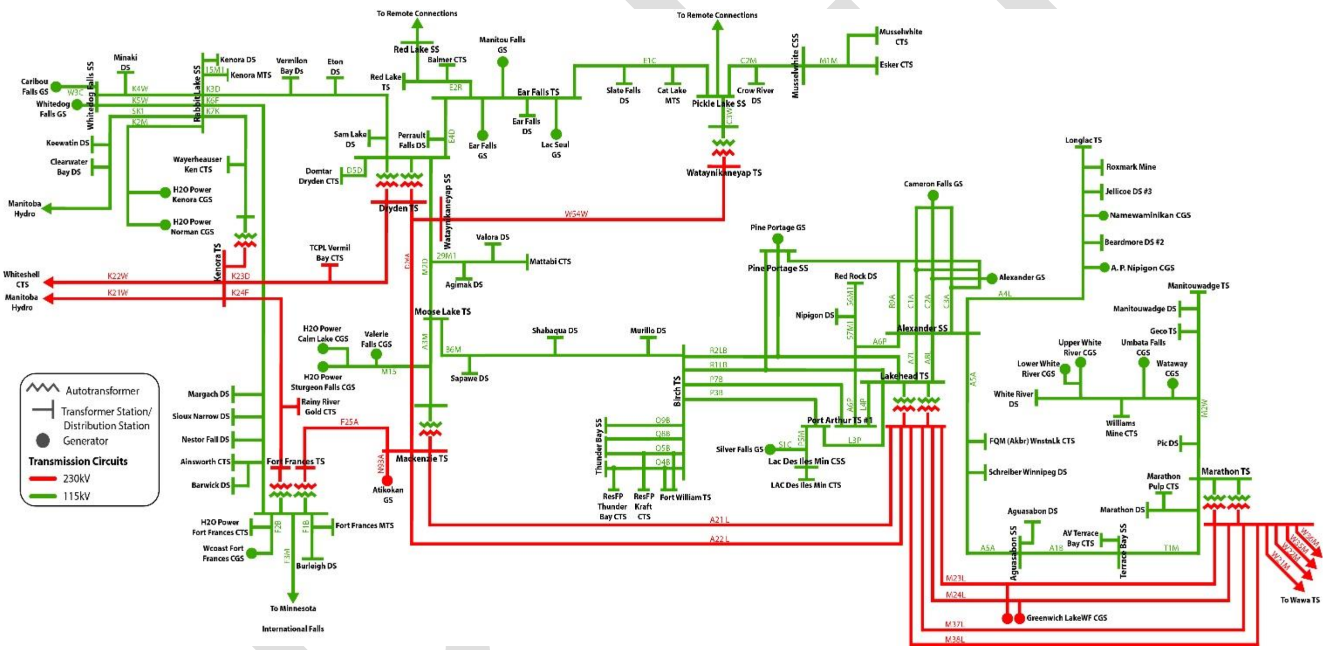
1. Introduction and Background

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 Northwest 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 | Northwest Region



The previous Northwest Scoping Assessment was published in January 2015 and recommended four sub-regions each with their own IRRP. These IRRPs include Greenstone-Marathon (published June 2016), Thunder Bay (published December 2016), West of Thunder Bay (published July 2016), North of Dryden (published January 2015).

The first phase of the current regional planning cycle, the Hydro One-led Needs Assessment, was completed in July 2020.

2. Objectives

The Northwest 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 Northwest 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 Northwest; and,
- Develop an implementation plan that is flexible in order 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 the needs of the Northwest region. The plan is a joint initiative involving, Hydro One Networks Inc. (Transmission), Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., Synergy North and the IESO. These organizations are defined as the Working Group for the Northwest IRRP.

The plan will focus on these specific items:

- Thunder Bay Area Capacity Need
- Marathon Area Capacity Need
- Refresh North of Dryden Area System Capability
- Non-Wires Alternatives for Kenora MTS Capacity Need
- Ring of Fire Connection Scenario
- Load Restoration
- End of Life
- Any additional needs that emerge in carrying out the IRRP

Like all IRRPs, the Northwest IRRP will integrate: forecast electricity demand growth, conservation and demand management ("CDM") in the area, distributed energy resources ("DER") uptake, transmission and distribution system capability, relevant community plans, and bulk system developments as applicable.

Based on the identified needs, the Northwest IRRP process will consist of the following activities:

1. Development of a Stakeholder Engagement Plan.

2. Development of an updated 20-year demand / load forecast for the entire region. The forecast will be used to confirm that there are no significant changes from past IRRPs in areas where no needs were flagged in the 2020 Needs Assessment. In areas with potential capacity needs (such as the Thunder Bay and Marathon areas), the forecast will be compared against the load meeting capability to determine the timing of needs.
3. Assessment of the adequacy of transformer station ratings, load meeting capabilities and reliability.
    a. Identify or confirm the transformer station capacity needs and sufficiency 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 the Local Distribution Companies ("LDCs").
4. Assessment of options for confirmed needs. Options are evaluated on the basis of technical feasibility, economics, and reliability performance as well as consideration of other factors raised through community engagement.
5. Development of the long-term recommendations and the implementation plan.
6. Completion of the IRRP report documenting the 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 actions:

- Active monitoring
- Project development work to shorten lead time for the project, 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 the near-term requirements, until longer-term solutions could come into service
- Additional pilots, studies and/or engagement to gather more information
- Coordination with other planning or related processes (e.g., community or bulk system planning)

Should the IRRP identify the need for infrastructure investment, the IRRP will provide a rationale and define high-level project requirements to support project development and implementation to be carried out by other proponents. The outcomes from the IRRP will help inform transmitter and LDC rate filings and any related transmission/resources acquisitions 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 IRRP.

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, 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 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)
        i. Supply capability
        ii. Load security
        iii. Load restoration requirements

- 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 core Technical Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator (Team Lead for IRRP)
- Hydro One Networks Inc. (Hydro One Transmission)
- Hydro One Networks Inc. (Hydro One Distribution)
- Atikokan Hydro Inc.
- Fort Frances Power Corporation
- Sioux Lookout Hydro Inc.
- Synergy North
- Other transmitters and distributors as needed

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, Timeline, and Primary Accountability

Num	Activity		Deliverable(s)	Timeframe
1	**Develop the Planning Forecast, including scenarios for sensitivity analyses, as required**	*IESO / LDCs with input from Hydro One*	Long-term planning forecast scenarios	Feb 2021 – Apr 2021
1.1	Establish historical coincident and non-coincident peak demand information	*IESO*		
1.2	Establish historical weather correction, median and extreme conditions	*IESO*		
1.3	Establish gross peak demand forecast for LDC service areas	*LDCs*		
1.4	Establish existing, committed and potential DG	*LDCs*		
1.5	Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	*IESO*		
1.6	Develop planning forecast scenarios for sensitivity analyses	*IESO*		
2	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	Load transfer capabilities under normal and emergency conditions	Feb 2021 – Apr 2021
3	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	Relevant community plans	Feb 2021 – Apr 2021

Num	Activity		Deliverable(s)	Timeframe
4	**Complete system studies to identify needs over a twenty-year period**	*IESO, Hydro One Transmission*	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q2-Q3 2021
4.1	Obtain PSS/E base case including bulk system assumptions as identified in Section 3.2			
4.2	Apply reliability criteria as defined in ORTAC			
4.3	Confirm and refine the need(s) and timing/load levels			
5	**Develop Options and Alternatives**		Develop flexible planning options for forecast scenarios	Q3-Q4 2021
5.1	Develop energy efficiency options, with consideration for previous LAPS findings	*IESO and LDCs*		
5.2	Develop local generation options, with consideration for previous LAPS findings	*IESO and LDCs*		
5.3	Develop transmission and distribution options	*IESO, Hydro One Transmission, and LDCs*		
5.4	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
5.5	Develop portfolios of integrated alternatives	*All*		
5.6	Technical comparison and evaluation	*All*		
6	**Plan and Undertake Community & Stakeholder Engagement**	*IESO / LDCs and Hydro One with support as needed*	Community and Stakeholder Engagement Plan; Input from local communities	Ongoing as required
6.1	Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an			

Num	Activity		Deliverable(s)	Timeframe
	interest in the study area, and the Métis Nation of Ontario			
6.2	Develop communications materials			
6.3	Undertake community and stakeholder engagement			
6.4	Summarize input and incorporate feedback			
7	**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	Q1-Q2 2022
8	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	IRRP report	July 2022

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