Integrated Regional Resource Plan

Northwest Region
January 2023

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List of Acronyms

Acronym	Definition
APS	Achievable Potential Study
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LDC	Local Distribution Company
LTE	Long-term Emergency
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
TS	Transformer Station
ULTC	Under-Load Tap Changer

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

This IRRP was prepared on behalf of the Technical Working Group (Working Group) of the Northwest region which included the following members:

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

The Working Group assessed the reliability of electricity supply to customers in the Northwest Region over a 20-year period beginning in 2021; developed a plan that considers opportunities for regional coordination in anticipation of potential demand growth and varying supply conditions in the region; and developed an implementation plan for the recommended options while maintaining flexibility to accommodate changes in key conditions over time.

The Northwest Working Group members agree with the Integrated Regional Resource Plan (IRRP)'s recommendations and support the implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations. The Northwest Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Northwest region over the next 20 years from 2021 to 2040. 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. A geographic map of the Northwest region is shown in Figure 1-1. 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. A single line diagram of the electrical infrastructure in the region is shown in Figure 1-2.

Northwest regional electricity demand is winter peaking and, over the last five years, has grown on average by 1.1% per year. Electricity supply to the Northwest region is provided through the 230 kV East-West Tie circuits from Wawa TS, as well as from interconnections with Manitoba and Minnesota. Local generation in the region is predominantly hydroelectric and biomass-fueled.

The region's electricity is delivered by five local distribution companies (LDCs): Hydro One Networks Inc., Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., and Synergy North. Hydro One Networks is also the lead transmitter in the region for regional planning purposes. Note that three transmitters own assets in the Northwest region: Hydro One Networks, Nextbridge Infrastructure, and Wataynikaneyap Power. As the lead transmitter, Hydro One Networks coordinates the involvement of other transmitters as necessary. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group composed of the aforementioned LDCs and Hydro One Networks.

Development of the Northwest IRRP was initiated in Jan 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and the Scoping Assessment Outcome Report in Jan 2021 by the IESO.[1] The Scoping Assessment identified needs that should be further assessed through an IRRP. The Working Group was then formed to gather data, identify near- to long-term needs in the region and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;

[1] The Needs Assessment can found on Hydro One's Northwest Ontario regional planning website and the Scoping Assessment Outcome Report can be found on the IESO's Northwest regional planning engagement website.

- Demand forecast scenarios, distributed generation assumptions, and conservation and demand management are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- An update on the Supply to the Ring of Fire study is provided in Section 8
- A summary of engagement to date and the next steps are provided in Section 9; and
- The conclusion is provided in Section 10

Figure 1-1 | Geographic Map of the Northwest Region

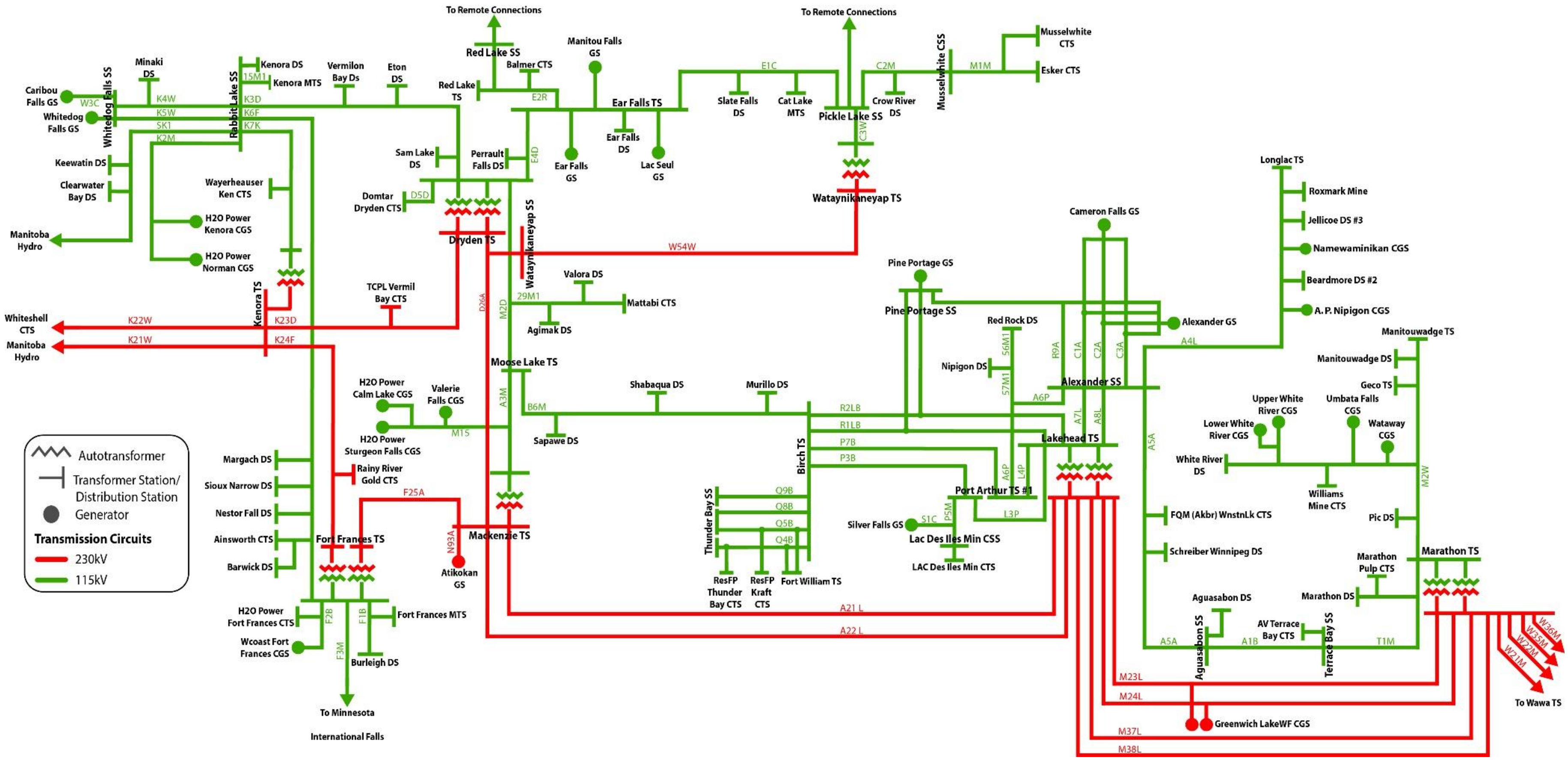

Figure 1-2 | Electricity Infrastructure in the Northwest Ontario Region

2. The Integrated Regional Resource Plan

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

There are several recent or ongoing transmission reinforcement projects in the Northwest region including the:

- East-West Tie Reinforcement (new double circuit 230 kV line from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS),
- Waasigan Transmission Line Project (Phase 1 being a new double circuit 230 kV line from Lakehead TS to Mackenzie TS and Phase 2 being a new single circuit 230 kV line from Mackenzie TS to Dryden TS), and
- Wataynikaneyap Transmission Project (new single circuit 230 kV line from Dinorwic Junction near Dryden to Wataynikaneyap TS near Pickle Lake as well as 115 kV remote connection circuits north of Pickle Lake and Red Lake).

Taken together, these projects reinforce many of the 230 kV transmission paths in the region. With these reinforcement projects, the infrastructure in the Northwest will be adequate to support forecast growth except for some station capacity and local operational needs. There are no new transmission projects recommended as a result of this Northwest planning initiative.

Northwest electricity demand growth is driven by the mining sector which tends to add large incremental blocks of load, often with short lead times. Therefore, this IRRP also studied several high growth sensitivities beyond forecast demand levels to test the robustness of the plan.

The plan below is organized into two sections: near-/medium-term recommendations and ongoing monitoring. Near-/medium-term recommendations include actions or further studies to be undertaken by Working Group member(s) by a specified date. These recommendations address needs with a high level of forecast certainty and requires firm commitments in this cycle of regional planning. Ongoing monitoring activities address long-term needs or potential needs flagged in high growth sensitivities that may emerge but are not yet certain based on the latest electricity demand forecast. This approach ensures that the IRRP provides clear guidance on investments needed in the near future while remaining flexible to consider new information such as electrification, energy efficiency, and industrial/mining development plans.

2.1 Near-/Medium-Term Recommendations

The near- and medium-term recommendations are summarized in Table 2-1 and further discussed below.

Table 2-1 | Summary of Near- and Medium-Term Recommendations

Need/Subsystem	Recommendation	Lead Responsibility	Required By
Kenora MTS Station Capacity	Non-wires alternatives (NWAs) can be cost effective depending on distribution system benefits; Kenora MTS will be a potential focus area for the IESO's Local Initiative Program and Synergy North will lead further non-wires analysis in local planning	Synergy North; IESO	2029
Crilly DS Station Capacity	NWAs not suitable; Hydro One Distribution will refine options for refurbishment or a new station in local planning	Hydro One Distribution	2027
Margach DS Station Capacity	NWAs not suitable; Hydro One Dx will install fan monitoring if growth materializes and monitor for additional growth that might necessitate a second transformer	Hydro One Distribution	2023
Fort Frances MTS Customer Reliability	Reconfiguration of Fort Frances TS to reduce supply interruptions to Fort Frances MTS during transmission system outages; Fort Frances Power and Hydro One Transmission will refine configuration in local planning	Fort Frances Power; Hydro One Transmission	As Soon as Practical
E1C Operation and High Voltage	With the new W54W circuit in-service, part of the Wataynikaneyap Transmission Project, E1C will be operated "normally open" and additional reactors will be installed at/near Pickle Lake SS to manage high voltages; Hydro One and IESO will collaborate in the Regional Infrastructure Plan to refine location of open point and reactor sizing	IESO Hydro One Transmission	As Soon as Practical

Note that all costs discussed below are planning-level estimates (-50% to +100%) provided for the purpose of comparing options. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

2.1.1 Kenora MTS Station Capacity

Kenora MTS is expected to reach capacity in 2029. There are no upstream supply constraints aside from the station capacity itself. The "wires" options range from installing an additional transformer at the existing station ($5M) to a new station across town ($30M) that would also incrementally improve reliability and provide distribution system benefits.[2] The wires options and distribution benefits are further discussed in Section 7.1.4.1. Based on the forecast hourly demand and associated energy-not-served profiles, three non-wires alternatives (NWAs) were identified including a 4 MW gas turbine facility, a 6-hour 4 MW battery, and a hybrid option of energy efficiency and demand response. The cost of these NWAs generally falls between the cost of expanding the existing station and a new station.[2] Therefore, the decision to pursue NWAs versus traditional wires options rests on distribution system benefits that can be realized by each option. NWA options analysis is further discussed in Section 7.1.4.2.

The technologies, regulatory framework, and protocols required to implement dispatchable NWAs to meet local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[3] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Pilot and further refine NWAs for Kenora MTS.

Therefore, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement NWAs if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[4] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program becomes available.

2.1.2 Crilly DS Station Capacity

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to

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[2] The methodology for calculating cost estimates is set out in Section 7.1.1

[3] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[4] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to the existing reliance on backup generation. Distributed energy resources cannot remove the reliance on backup power and provide reliability comparable with other standard supply arrangements. Furthermore, the pool of customers served at Crilly DS is too small to target demand-modifying solutions such as energy efficiency and demand response. The IRRP recommends that Hydro One Distribution conducts local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost. Options considered thus far include:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),
- Rebuild Crilly DS at a different location as a 115/25 kV HVDS,
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS, or
- Replace Crilly DS with a 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

Wires options for Crilly DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.2. Hydro One Distribution should monitor load growth to determine when a firm commitment to refurbish/rebuild Crilly DS is required.

2.1.3 Margach Station Capacity

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS. Margach DS is approximately 10 km east of Kenora. Non-wires alternatives are not capable of addressing this large near-term step increase in demand.

The IRRP recommends that Hydro One distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service but no recommendation beyond the fan monitoring is required today. Wires options for Margach DS and the rationale for not pursuing non-wires alternatives are further discussed in Section 7.1.3.

2.1.4 Fort Frances MTS Customer Reliability

Fort Frances MTS, a step-down transformer station that supplies LDC loads in Fort Frances, is supplied from the nearby Fort Frances TS. The two stations are located immediately across the street from each other. Fort Frances TS is configured in a manner that would result in Fort Frances MTS supply interruptions during certain transmission outages. Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. While the station equipment has not yet reached end-of-life, most equipment has reached or exceeded its typical useful life (as defined in the OEB's Asset Depreciation Study[5]) and will need to be replaced gradually over the next 10-15 years. While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power which could quickly use up the remaining station capacity. Furthermore, 115 kV breakers at Fort Frances TS are also approaching end of life around 2027 which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS. Customer reliability, sustainment, and potential capacity needs are further discussed in Sections 6.2.2 and 0.

Fort Frances Power is developing a roadmap for Fort Frances MTS considering the replacement of aging assets, demand growth, and reliability improvements by reconfiguring supply from Fort Frances TS. Considering these needs simultaneously will ensure the most optimal and cost-effective outcome. Hydro One has proposed several Fort Frances TS reconfigurations that would incrementally improve customer reliability for Fort Frances TS and are further discussed in Section 7.2. The IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and refine a configuration in local planning.

2.1.5 E1C Operation and High Voltage

With the new 230 kV Wataynikaneyap circuit W54W in-service, operating circuit E1C closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W. The IRRP confirms that E1C should be operated normally open. This configuration is consistent with the 2015 North of Dryden IRRP.

With E1C operated normally open, high voltage arises due to line charging. Studies show that opening E1C closer to the Ear Falls TS end minimizes high voltage issues. Additionally, the IRRP recommends an additional reactor (approximately 10 MVar) at or near Pickle Lake SS.

E1C closed loop transfer limitations and E1C normally open high voltage issues are further discussed in Section 6.2.3. The IESO and Hydro One Transmission will collaborate in the Regional Infrastructure Plan to refine the location of the open point on E1C and the sizing of the reactor, considering asset conditions and costs.

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[5] The OEB's Asset Depreciation Study can be found on the Ontario Energy Board's website.

2.2 Ongoing Monitoring

In addition to the needs addressed in the near- and medium-term plan above, there are several long-term or potential needs that may emerge over the forecast horizon. These needs will be monitored by the Working Group to determine when future planning studies should be triggered.

2.2.1 Station Capacity Needs Emerging in the Long-term

White Dog DS and Marathon DS are expected to reach capacity in 2032 and 2038 respectively. In both cases, current demand already exceeds 85% of the station capacity but forecast growth is modest over the forecast horizon. As with many stations across the Northwest, growth can materialize quickly if industrial development intensifies. Therefore, White Dog DS and Marathon DS should be monitored, and further planning activities should be triggered at least five years before anticipated capacity needs to enable consideration of non-wires alternatives. White Dog DS and Marathon DS station capacity needs are further discussed in Section 6.2.1.4 and 6.2.1.5.

2.2.2 Potential Growth in the Red Lake Area

The Red Lake area has significant mining activity and electricity demand is forecast to grow from 58 MW today to 70 MW by 2028. The W54W circuit recently completed as part of the Wataynikaneyap Transmission Project will help relieve constraints on the existing 115 kV circuits to Red Lake.

No capacity needs are anticipated based on the current demand forecast which was finalized by the end of 2021. However, the Working Group is aware of additional potential mining projects that are not captured in the current reference scenario demand forecast.[6] The timing and amount of load associated with these mines are not yet certain but, considering the typical size of new mining projects, remaining capacity in the Red Lake area can quickly be exhausted. Section 6.3.1 identifies the load meeting capability for the Red Lake area as well as constraints on the supply to Ear Falls and Dryden. Depending on the demand that materializes, bulk system enhancements beyond the scope of this IRRP (e.g., Waasigan Transmission Line Project Phase 2) may also be required.

The Working Group will monitor growth in the Red Lake area to determine when future planning activities should be triggered. The IESO will also continue to update the mining demand forecast, including mines in the Red Lake area, to inform ongoing bulk planning activities.

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[6] As described in Section 5.4, for the purpose of this IRRP, the mining sector demand forecast was finalized by the end of 2021. The Working Group is aware of additional future mining projects that were either brought to the awareness of the Working Group after 2021 or were not yet certain enough for inclusion in the demand forecast. The IESO is updating the mining sector demand forecast by end of Q1 2023 and will provide updates to the Working Group to inform the Regional Infrastructure Plan.

2.2.3 Potential Growth in the Fort Frances Area

Several large industrial customers have expressed interest in connecting in the Fort Frances area; these customers' potential loads are not included in the current demand forecast. While the incremental electricity demand associated with these customers (approximately totalling 100 MW) may be significant, no firm commitments have been made.

No supply capacity needs are anticipated based on the current demand forecast. Section 6.3.2 identifies the load meeting capability of the Fort Frances area. The Working Group will monitor growth in the Fort Frances area to determine when future planning activities should be triggered.

2.3 Coordination with ongoing Bulk Planning and Project Implementation Activities

In April 2022, as part of the IESO's obligation to recommend the specific scope and timing of the Waasigan Transmission Line Project, the IESO recommended a staged approach for construction with Phase 1 (a new line from Thunder Bay to Atikokan) being placed in-service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the region, update the mining sector demand forecast and provide an update on the need for Phase 2 (a new line from Atikokan to Dryden) by Q2 2023.

The IESO is also conducting a Northern Ontario Voltage Study to identify reactive compensation needs across northern Ontario. There are several recently implemented or planned major transmission reinforcement projects in the north including the East-West Tie Reinforcement, Waasigan Transmission Line Project, Wataynikaneyap Transmission Project, and Northeast Bulk Plan recommendations.[7] These projects will impact the voltage characteristics across the northern bulk transmission system, including the Northwest region. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

The Waasigan Transmission Line Project and Northern Ontario Voltage Study are further described in Section 4.2. The IESO will continue to update the Working Group regarding ongoing bulk planning and project implementation developments for consideration in the Regional Infrastructure Plan.

In addition to the plans above, the IESO is carrying out a Supply to the Ring of Fire study in parallel with this IRRP. The preliminary findings are discussed in Section 8. The Supply to the Ring of Fire Study will continue in 2023 and the IESO will update the working group on findings for consideration in future regional planning activities.

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[7] The Need for Northeast Bulk System Reinforcements report can found on the Northeast Bulk Planning webpage.

3. Development of the Plan

3.1 Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 defined planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each planning region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;

2. A Scoping Assessment, led by the IESO, identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;

3. An Integrated Regional Resource Plan (IRRP), led by the IESO, proposes recommendations to meet the identified needs requiring coordinated planning; and/or

4. A Regional Infrastructure Plan (RIP), led by the transmitter, provides further details on recommended wires solutions.

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

Regional planning is not the only type of electricity planning in Ontario. Other planning activities include bulk system planning, carried out by the IESO, and distribution system planning, carried out by LDCs. There are inherent overlaps in these three levels of electricity infrastructure planning.

The IESO completed a review of the regional planning process following the completion of the first cycle of regional planning for all 21 regions. The IESO's Regional Planning Process Review report is posted on the IESO's website. Implementation of Regional Planning Process Review recommendations by the IESO, Ontario Energy Board, and its Regional Planning Process Advisory Board are ongoing.

3.2 The Northwest Region and IRRP Development

The process to develop the Northwest IRRP was initiated in January 2021 following the publication of the Needs Assessment report in July 2020 by Hydro One and Scoping Assessment Outcome Report in January 2021 by the IESO. As per the 18-month timeline, triggered by the publication of the Scoping Assessment Outcome Report, the original publication date for the Northwest IRRP was scheduled for July 13, 2022.

In April 2022, the IESO wrote to the Ontario Energy Board (OEB) to provide notice that the IESO required an additional six months to complete the IRRP. The IRRP's original scope was expanded to include additional key developments in the Northwest region. The expanded scope enabled more extensive stakeholder engagement, consideration of additional growth sensitivities, and better alignment with ongoing bulk studies across the Northwest and Northeast regions. Based on the IESO's estimate of the additional time required to incorporate the expanded scope, the new expected posting date for the Northwest IRRP was extended to January 13, 2023.

4. Background and Study Scope

This is the second cycle of regional planning for the Northwest region. In the first cycle of regional planning, the region was divided into four sub-regions, each with its own IRRP:

- Greenstone-Marathon (published June 2016)
- Thunder Bay (published December 2016)
- West of Thunder Bay (published July 2016)
- North of Dryden (published January 2015)

A summary of each of the above IRRPs can be found in the 2021 Scoping Assessment Outcome Report[8]. The Scoping Assessment for this planning cycle recommended a single IRRP covering the entire Northwest region. This report presents an integrated regional electricity plan for the next 20-year period from 2021-2040.

Note that two new transmission system projects, the East-West Tie ("EWT") reinforcement and the Wataynikaneyap Transmission Project ("Watay Project") came into service during the current IRRP study. They were both assumed to be in-service for the purpose of this IRRP's technical assessments. 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 new EWT circuits were placed in service in March 2022. The Wataty Project includes a new 230 kV circuit, W54W, between Wataty 230/115 kV TS and Dinorwic Junction on circuit D26A, which runs between Dryden TS and Mackenzie TS. W54W was placed in service in August 2022. The Wataty Project includes the connection of ten remote First Nation communities north of Pickle Lake (electrically supplied by Pickle Lake SS) and an additional seven remote First Nation communities north of Red Lake (electrically supplied by Red Lake SS). As of Q4 2022, work is still underway to connect Pickle Lake and Red Lake remote communities, but they were assumed to be in service for the purpose of this IRRP's technical assessments.

4.1 Study Scope

This IRRP identifies electricity needs in the Northwest Region and develops and recommends options to meet these needs. A list of transmission facilities included in the scope of this study can be found in Appendix C. The plan was prepared by the IESO on behalf of the Working Group. The plan includes consideration of forecast electricity demand growth, conservation, and demand management (CDM), distributed generation (DG), transmission and distribution system

[8] The 2021 Scoping Assessment Outcome Report can be downloaded from the Northwest Regional Planning engagement webpage.

capability, relevant community plans, condition of transmission assets and developments on the bulk transmission system.

The Northwest IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
- Examining the load meeting capability (LMC) and reliability of the existing transmission system, considering facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC, NERC, and NPCC criteria;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
- Confirming identified end-of-life asset replacement needs and timing with LDCs and transmitters;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including conservation and demand management;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

For the Northwest IRRP, areas of interest with high growth potential beyond forecast demand levels were identified through stakeholder engagement. Additional high sensitivity studies were performed for these areas to test the robustness of the system to supply higher than forecast demand.

4.1.1 Scope of Regional Planning Regarding New Connections

The purpose of the IRRP is to identify and address reliability needs that require coordination between transmitters, distribution companies, and the IESO. In the Northwest region, growth is driven in large part by industrial customers, predominantly in the mining sector. A subset of these customers are not currently connected to the electricity grid but are pursuing grid connection in the near term. The IRRP used the best available information to accurately simulate the connection arrangement of future customers and projects. However, IRRP technical studies were focused on evaluating the overall adequacy of regional infrastructure to supply forecast demand rather than the capability to supply any specific new project. The IRRP did not study the local connection requirements of any individual project unless there was an opportunity to align with broader regional needs.[9]

4.2 Parallel Bulk Planning Activities

The Waasigan Transmission Line Project and the Northern Ontario Voltage study are proceeding in parallel with this IRRP and the upcoming Regional Infrastructure Plan. Findings and recommendations from these bulk planning activities will inform ongoing regional planning activities.

4.2.1 Waasigan Transmission Line Project

The Waasigan Transmission Line Project ("Waasigan Project"), formally the Northwest Bulk Line, was identified in the Government's 2013 and 2017 Long Term Energy Plans (the "LTEPs") as a priority project to:

- Increase electricity supply to the region west of Thunder Bay;
- Provide a means for new customers and growing loads to be served with clean and renewable sources that comprise Ontario's supply mix; and,
- Enhance the potential for development and connection of renewable energy facilities.

The LTEPs divided the Waasigan Project into three phases:

- Phase 1 - a line from Thunder Bay to Atikokan;
- Phase 2 - a line from Atikokan to Dryden; and,
- Phase 3 - a line from Dryden to the Manitoba border through Kenora.

Following the 2013 LTEP, the Ontario Government issued an Order in Council, also in 2013, that amended Hydro One's license to develop and seek approval for the Waasigan Project according to the scope and timing specified by the IESO.

In 2018, the IESO recommended that Hydro One commence development work (i.e., complete the Environmental Assessment) for Phase 1 and Phase 2 based on the timing of projected supply capacity needs and the risk of them materializing earlier. The IESO committed to ongoing monitoring to determine when construction of both Phase 1 and Phase 2 should begin and to confirm that they are the best course of action to meet the needs.

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[9] Potential customers seeking connection should note that participation in the IRRP does not replace connection processes, namely Customer Impact Assessments (CIA) or System Impact Assessments (SIA). Furthermore, the absence of regional reliability needs identified through the IRRP in a particular area does not guarantee that connection requests in that area will be approved in a CIA or SIA.

In 2022, the IESO updated the demand forecast for the region west of Thunder Bay with information from the IRRP demand forecast and feedback from stakeholders. The mining sector demand forecast drove the majority of the demand growth and is further discussed in Section 5.4. The updated demand forecast showed a need for Phase 1 starting in 2025 and a temporary need for Phase 2 in 2026 and 2027, but not thereafter as some existing mining projects reach end of life. Therefore, the IESO recommended a staged approached for construction where Hydro One would construct the Project to meet near-term system capacity needs, with Phase 1 being placed in service as close to the end of 2025 as possible. The IESO will continue to monitor developments in the Region and provide an update in Q2 2023 on the expected need date for Phase 2. This is a balanced approach to accommodate growth in a timely manner while managing ratepayer risks.

The IESO recognizes that a firm need for Phase 2 could materialize quickly given the potential for additional growth in the region. The IESO is currently in the process of updating the mining demand forecast to reflect additional information received over the past year since the last forecast iteration and to better capture future growth driven by electrification trends and government policy. The forecast update is expected to be completed in Q1 2023.

4.2.2 Northern Ontario Voltage Study

The IESO is conducting a Northern Ontario Voltage Study to identify reactive compensation needs across the bulk system in northern Ontario. The Northern Ontario Voltage Study is expected to be finalized in early 2023.

4.3 Supply to the Ring of Fire

The Ring of Fire is a remote area approximately 500 km north of Thunder Bay rich in critical minerals but without grid power supply. The decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as they are the direct beneficiaries, or with the provincial and federal governments, to advance broader policy objectives.

Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with this IRRP to help inform government policy and potential customers seeking connection. This study outlines opportunities for alignment, updated high-level transmission supply cost estimates, updated avoided diesel system costs from connecting remote communities, and greenhouse gas reductions as a result of supplying remote communities and potential mines from the electricity grid instead of local generation. The preliminary findings are discussed in Section 8.

The study scope and timing of this ongoing study will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

5. Electricity Demand Forecast

This section describes the development of the demand forecast for the Northwest Region that underpins this IRRP. The 20-year forecast has three components:

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the Northwest and is based on information submitted by local distribution companies.

- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This is typically comprised of large industrial customers that have their own transformation station. The transmission-connected forecast is informed by direct engagement with customers.

- **Mining Sector**: The mining sector forecast captures electricity demand from both existing grid-connected and known future mining projects that are not yet grid-connected. The mining sector forecast is informed by data from government, industry publications, and engagement individual project proponents. Note that electricity demand from existing mining projects is also reflected in the above transmission- and distribution-connected forecast components. When the mining sector component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting

Each forecast component is described in detail below. Note that the forecasts in this section refer to the non-coincident peak demand forecast (i.e., the sum of each station's individual peak demand). Coincident forecasts (i.e., contribution of each station to the overall peak demand hour) for the subsystem in question are used for the purpose of identifying need dates and options analysis in Section 6 and 7. Coincident forecasts are found by applying a coincidence factor based on the contribution of each station to the subsystem's coincident peak over the past five years.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Northwest IRRP forecast was created prior to October 2022, the Ontario Energy Board has also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.[10]

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[10] The Load Forecast Guideline can be found on the Ontario Energy Board's website.

5.1 Historical Demand

Figure 5-1 shows the net and gross historical demand over the last five years in the Northwest region. Distribution-connected customer historically make up approximately 55% of peak demand with the remainder made up of transmission-connected customers. Growth has been steady over the last five years, with an average annual demand growth rate of 1.1% and Northwest demand hovering just over 800 MW from 2018 through 2020. Northwestern Ontario is winter peaking, with the peak demand hour for each year typically occurring on winter evenings between 7 p.m. And 11 p.m.

Existing distributed generation resources historically contributed approximately 10-15 MW during peak demand conditions. This contribution was added back into the net demand forecast to arrive at the gross demand forecast. The 2020 gross demand was used as the starting point for the forecast unless station-level adjustments were necessary to account for anomalous demand conditions on a case-by-case basis.

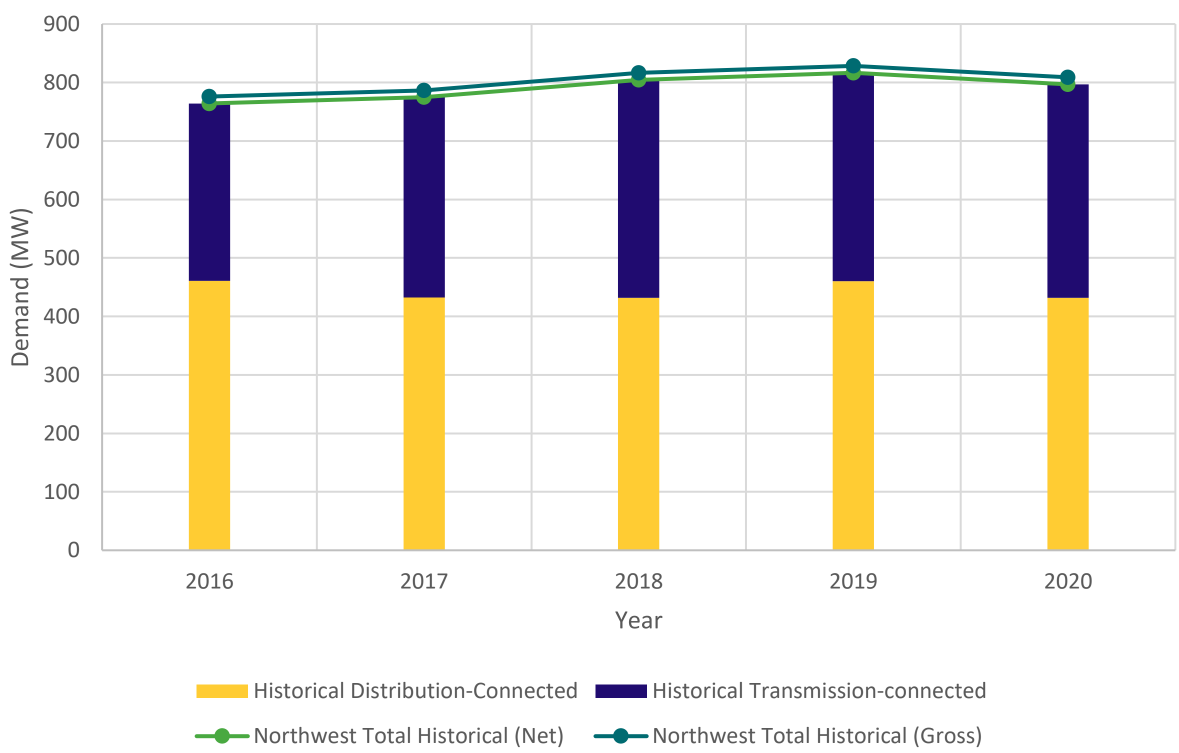


Figure 5-1 | 2016-2020 Historical Demand

5.2 Distribution-connected Forecast

The distribution-connected forecast component starts with a gross station-level demand forecast developed by local distribution companies for their service territory. The gross forecast was then modified to reflect the peak demand impacts of provincial conservation targets and distributed generation contracted through previous provincial programs such as FIT and microFIT[11] and adjusted to reflect extreme weather conditions to produce a reference scenario net forecast for planning assessments. Additional details related to the development of the distribution-connected demand forecast are provided in the sections below and in Appendix B.

5.2.1 Gross Local Distribution Company Forecast

Each participating local distribution company in the Northwest region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development and known connection applications within their service territories.

Note that the regional planning process relies on distributors to consider municipal and regional official plans and translate development plans into electrical demand forecasts. Distributors have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities they serve. More details on each distributor's demand forecast assumptions can be found in Appendix B.2 to B.6. Distributors are also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices, i.e., "natural conservation", but not for the impact of future distributed generation or new conservation measures which are accounted for by the IESO, as discussed in Section 5.2.2 and 5.2.3 below.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

[11] More information about the Feed-in Tariff can be found on the IESO's website.

The distribution-connected demand forecast compiled from distributors is adjusted to account for extreme weather conditions according to the methodology described in Appendix B.1. Figure 5-2 shows the total gross distribution-connected forecast for the Northwest region.

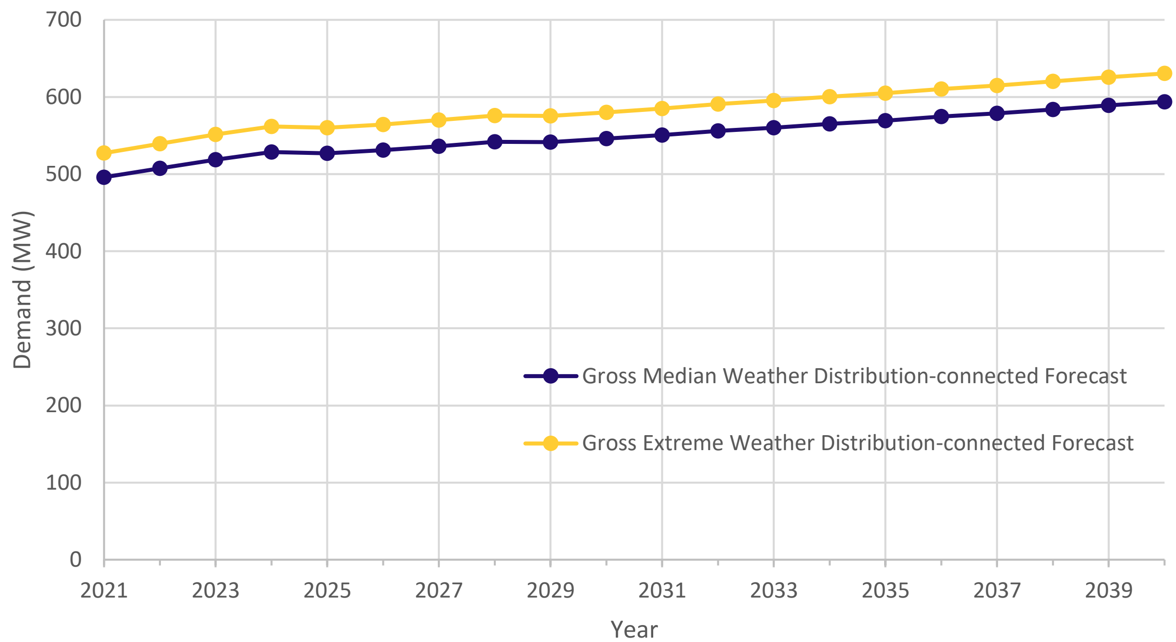


Figure 5-2 | Total Gross Median Weather Distribution-connected Forecast

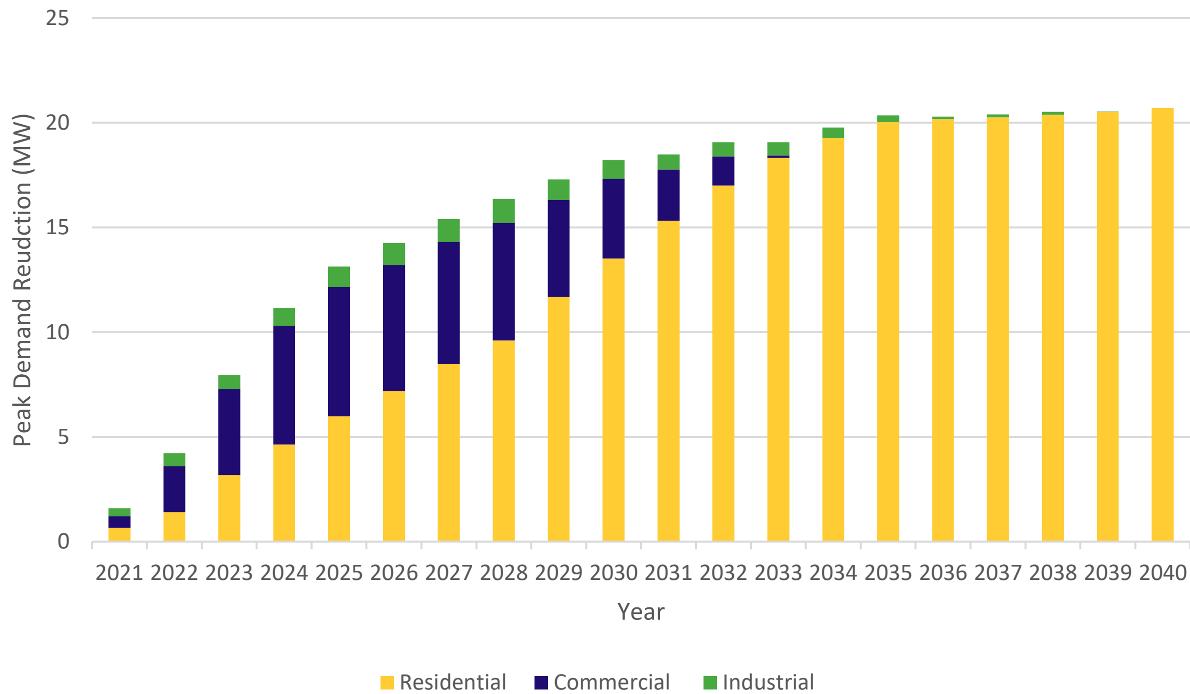
5.2.2 Contribution of Conservation to the Forecast

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

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

The estimates of demand reduction due to new program-related activities account for Ontario programs, federal programs that result in electricity savings in Ontario, and forecast future energy efficiency programs. The 2021 – 2024 CDM Framework is the central piece in which the IESO delivers programs on a province-wide basis to enable Ontario's electricity consumers to improve the energy efficiency of their homes, businesses, institutions, and industrial facilities.

Figure 5-3 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards and CDM programs) for residential, commercial, and industrial market segments. Additional details on the conservation forecast methodology are provided in Appendix B.9.



5.2.3 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, distributed generation in the Northwest region is also forecast to offset some peak demand requirements. The introduction of the Green Energy and Green Economy Act, 2009, and the associated development of Ontario's FIT Program, has increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed distributed generation capacity by fuel type and contribution factor assumptions can be found in Appendix B.10.

After reducing the demand forecast due to conservation as described above, the forecast is further reduced by the expected contribution from contracted distributed generation in the region (similar to the adjustment between net and gross historical demand described in Section 5.1 except with forward looking contracted distributed generation rather than existing distributed generation). Figure 5.5 shows the impact of distributed generation reducing the demand forecast. In the long term, the contribution of distributed generation is expected to diminish as these contracts expire. Note that any facilities without a contract with the IESO are not included in the distributed generation peak demand reduction forecast.

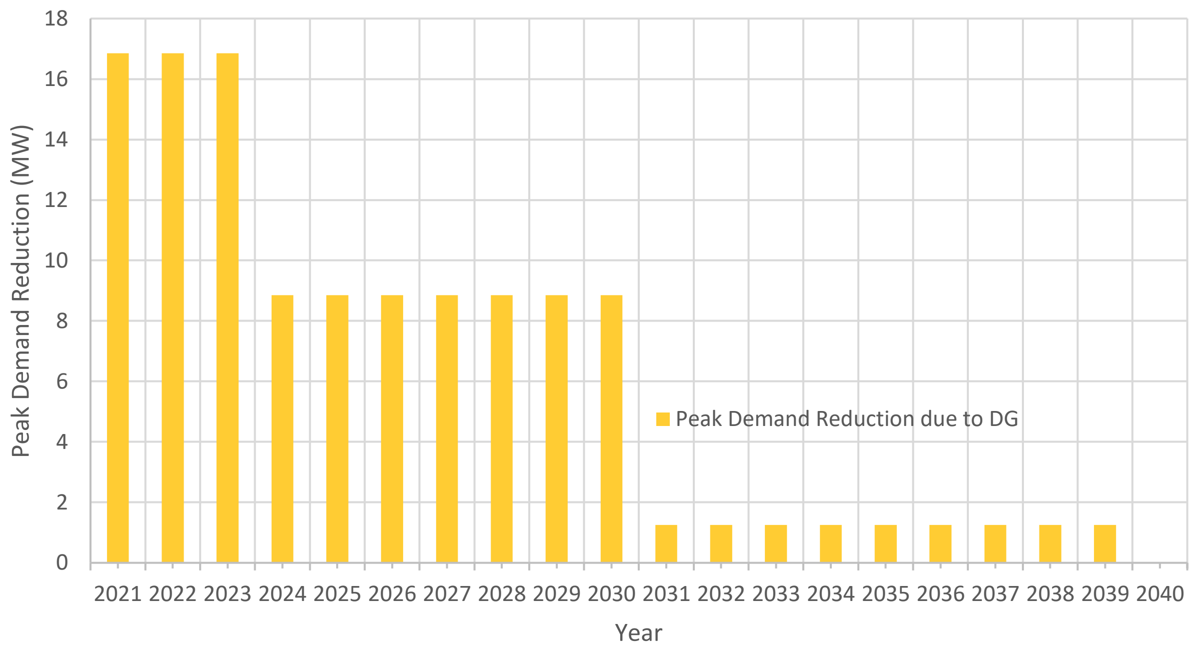


Figure 5-4 | Peak Demand Reduction to Demand Forecast due to Contracted Distributed Generation

5.3 Existing Transmission-connected Forecast

The Northwest region has fifteen customer transformer stations (CTS) that directly serve customers connected to the high-voltage transmission system. The IRRP relies on information from these customers to inform the transmission-connected forecast either directly through their account representative or through comments submitted through the IRRP engagement events. If, for a given station, no information about future demand changes is available, the default assumption is that demand at that station will remain the same as the average historical peak demand over the last five years. Figure 5-5 shows the total non-coincident transmission-connected customer demand forecast. The transmission-connected forecast is generally flat except for a few project expansions/retirements resulting in growth in 2026 and subsequent decline in 2028. Note that, unlike the distribution-connected forecast component, the transmission-connected component is not adjusted for extreme weather because industrial demand does not typically fluctuate with weather. Furthermore, while some customers have behind-the-meter generation facilities, they are not reflected in the forecast unless they are contracted with the IESO.

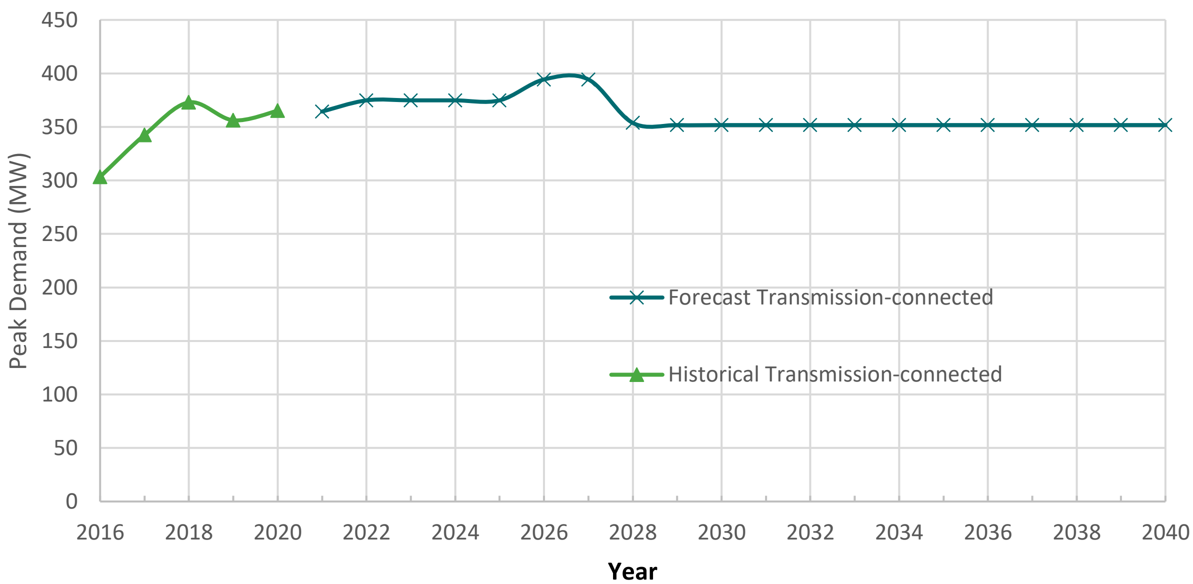


Figure 5-5 | Total Transmission-connected Demand Forecast

5.4 Mining Sector Forecast

In addition to the distribution- and transmission-connected forecasts, expansion of existing mines and new mining projects connecting to the grid are expected to make up the majority of the overall electricity demand growth in the Northwest region. As of Q4 2021, the IESO was aware of more than 20 potential future mining projects in the Northwest region at various stages of planning and development that had known electricity demand forecasts and projected in-service dates. The IESO is also aware of at least ~7-10 projects that are under consideration but have not yet progressed far enough to have an in-service date or electrical demand forecast. Note that information about future mining projects changes frequently. The IESO solicited public feedback on the mining demand forecast and associated list of known mining projects in May 2021. For this IRRP, the mining forecast was considered finalized by the end of 2021 to allow sufficient time for technical assessments that depended on forecast inputs. The mining projects incorporated in the IRRP mining forecast are listed in Appendix B.7.

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

Table 5-1 | Mining Forecast Scenario Descriptions

Scenario	Description
Low	- Conservative scenario including only existing mining projects and their extension/expansion/retirement plans - The full demand forecast for all existing mining projects is included
Reference	- Includes all demand in the low scenario plus the full undiscounted demand forecast from projects classified as "most likely" and "likely" - Aligned with 2021 Annual Planning Outlook[12] reference scenario

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

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

A project's likelihood is informed by factors such as the reliability of available data sources, development stage of the project, project timing, and permitting information. The IESO also incorporates input from the Ministry of Mines on the forecast and likelihood factors. The mining forecast scenarios are summarized in Table 5-1 above.

Figure 5-6 shows the low, reference, and high mining demand forecast scenarios. The total aggregate undiscounted (i.e., without consideration of likelihood factors) forecast demand from all known projects is also shown in a dashed line. Note that the total aggregate undiscounted forecast demand is not a realistic growth scenario since it is highly unlikely for all proposed mining projects to materialized. The undiscounted forecast is provided for transparency to illustrate the scale of potential demand growth considered in the low, reference, and high scenarios.

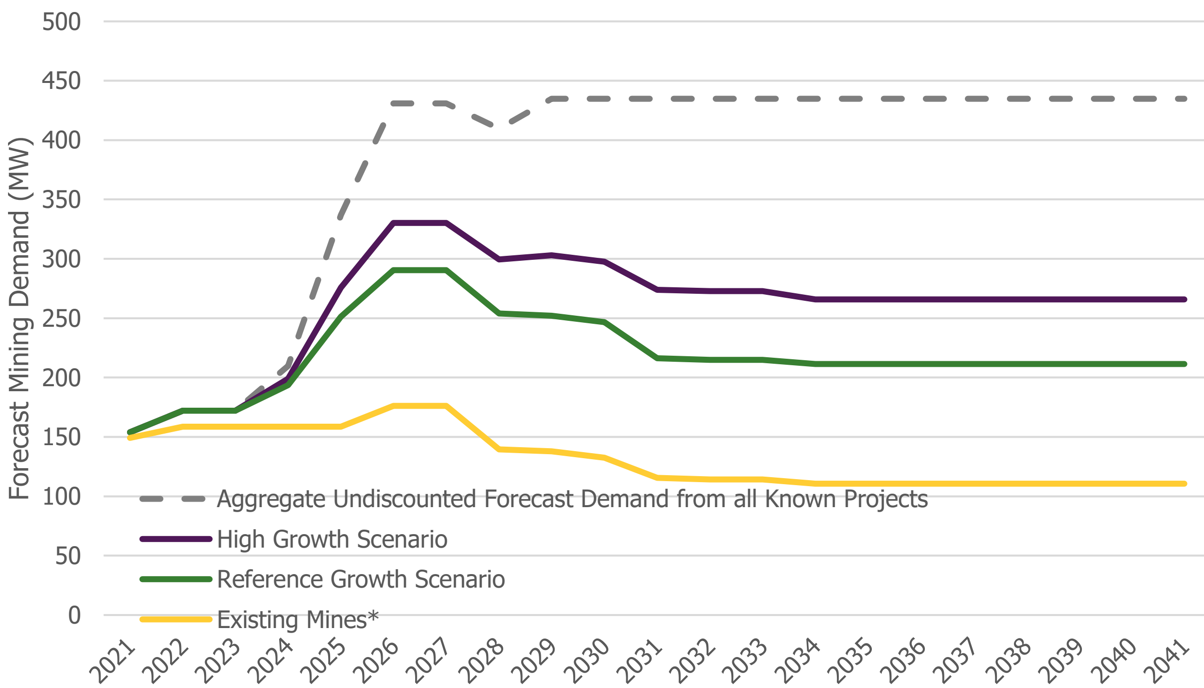


Figure 5-6 | Mining Demand Forecast

The mining sector already accounts for approximately 150 MW of demand today and is projected to grow to 290 MW by 2027 under the reference scenario. The low and high scenarios grow to 175 MW and 330 MW by 2027, respectively. Note that the IRRP does not provide disaggregated project-level forecast to preserve confidentiality.

Generally speaking, the existing mines (low) scenario informs local reliability needs that must be addressed even if no new mines materialize. The reference scenario informs the identification of needs that will likely arise and options to address those needs if/when mines materialize. Finally, the high scenario explores possible additional needs to test the robustness of the IRRP.

Note that in all scenarios, the mining forecast peaks in 2027 before declining for the remainder of the forecast horizon. This is a result of developing a project-based demand forecast as opposed to a top-line forecast for the mining sector as a whole. Information about existing and near-term projects are more readily available than information about long-term projects. Most known near- and mid-term new mining projects plan to come in-service by 2027. After 2027, demand begins to taper off as both existing and new mines reach the end of their planned operating life. The forecast scenarios do account for project extensions beyond their initial operating life but high uncertainty surrounding these extensions has meant that they were assigned low likelihood factors. In sum, the forecast performs well for predicting near- and medium-term mining growth but has less visibility of longer-term trends. Despite this shortcoming, a project-based demand forecast is more useful than a top-line forecast for the purpose of infrastructure planning. The project-based forecast provides relatively detailed information in the near- to mid-term when planning decisions must be made and provides critical geographic granularity necessary for transmission system studies.

5.5 Total Northwest Demand Forecast Scenarios

The total non-coincident Northwest demand forecast is shown in Figure 5-7 below. Note that when the mining forecast component is layered on top of the distribution-connected and transmission-connected components, only the contribution of new mining projects is shown to avoid double counting. The reference scenario Northwest demand grows to 1060 MW by 2027. The low and high scenarios growing to 945 MW and 1100 MW by 2027, respectively. Note that the discontinuity between historical and forecast demand from 2020 to 2021 is partly due to the extreme weather correction applied to the distribution-connected forecast.

The IRRP reference forecast is approximately 20% higher than the Annual Planning Outlook forecast for the Northwest zone. This difference is in part due to the non-coincidence of the IRRP's station-level forecast; the non-coincident forecast is typically 10-15% higher than the coincident forecast in the Northwest. The sum of regional planning forecasts is also generally higher than their bulk planning counterparts since regional forecasts capture potential growth at a greater granularity not all of which may materialize when aggregated at a larger geographic scale.

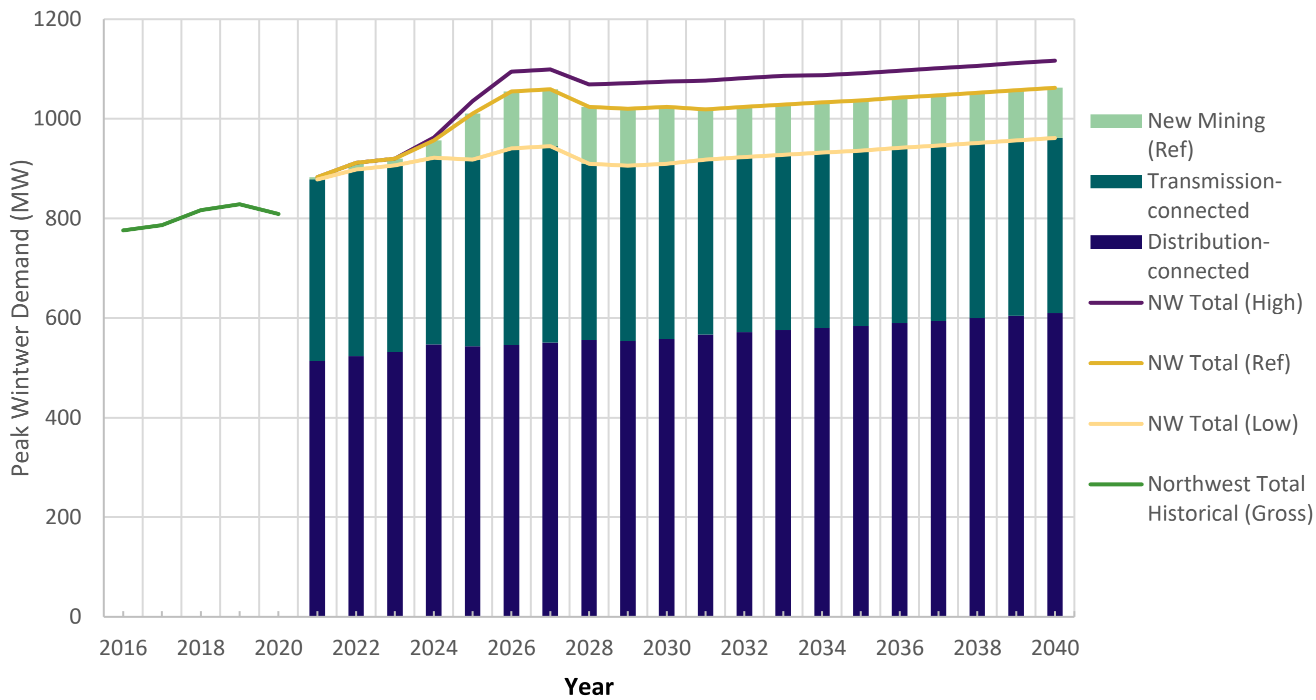


Figure 5-7 | Total Northwest Demand Forecast

5.6 Demand Profiling – Kenora MTS

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for stations or groups of stations with identified needs can be developed to characterize their needs with finer granularity. This is typically undertaken to inform an analysis of potential non-wires alternatives.

For this IRRP, hourly demand profiles were developed for Kenora MTS where a firm station capacity need was identified for which non-wires alternatives are promising. The Kenora MTS hourly demand profiles can be found in Appendix D.2. There were no other needs identified in this IRRP which could be addressed by non-wires alternatives.

Hourly demand profiles are created by first training a multiple linear regression model with historical data and then repeatedly applying the model under different weather/calendar variable permutations to forecast a range of possible future hourly profiles. The profiles are then ranked based on their median energy values. The median profile is scaled to match the peak demand forecast in each year and used to size and simulate non-wires alternatives as described in Section 7.1. A more fulsome description of the demand profiling methodology can be found in Appendix D.1.

Note that this data is used to roughly inform the overall energy requirements that a non-wire alternative would need to meet for the purposes of evaluating alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Further, this data is only used to select suitable technology types and roughly estimate operating costs. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification achieve greater adoption. The Working Group will continue to monitor these changes as part of the implementation of the plan.

6. Needs

This section summarizes the needs identified through the IRRP process. Taking into account committed transmission projects identified through bulk planning processes (i.e., the East West Tie expansion and the Waasigan transmission line), the Northwest region is generally adequate to support forecast electricity demand growth. The needs identified in the IRRP deal with localized supply to various pockets of demand in the Northwest as well as high-growth scenarios in areas identified as having strong future development potential.

This section is organized as follows:

- Section 6.1 summarizes the methodology for identifying needs,
- Section 6.2 describes firm station capacity and local operational needs (i.e., needs that would materialize under the reference forecast scenario), and
- Section 6.3 describes potential needs that may arise if higher than forecast growth materializes in select subsystems in the region.

Section 6.2.3 (E1C Operation and High Voltage Need), in addition to specifying the needs identified, will also discuss the recommended solutions since there are no "alternatives" that would normally be discussed in Section 7.

Note that bulk system needs are not in scope for the IRRP, which is focused on local reliability and ensuring that local/regional infrastructure can serve forecast demand. Nonetheless, this IRRP report flags any potential interactions between regional and bulk system needs.

6.1 Needs Assessment Methodology

Based on the reference demand forecast (extreme weather, net demand), system capability, transmitters' identified end-of-life asset replacement plans, and the application of ORTAC and NERC/NPCC standards, the 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.[13] 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. For the high growth sensitivities in Section 6.3, the LMCs for the subsystems in question are higher than the total forecast demand (both reference and high scenarios). Nonetheless, as these areas have been identified to have future development potential, the IRRP explores the existing limitations in these areas to identify the remaining LMC and inform future planning activities should higher growth materialize. Details regarding the power flow simulations, including the system topology and credible contingencies studied, can be found in Appendix C.

- **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[14] where like-for-like replacements have been established to be appropriate in earlier phases of the regional planning process. Instead, the IRRP focuses on a subset of end-of-life needs where there are interactions with other regional needs and where there may be opportunities to reconfigure or right-size assets. Therefore, in the sections below, end-of-life needs are described in conjunction with other needs where relevant.

[13] Some stations in the Northwest only have a single transformer in which case the transformer's LTR is the limiting element.
[14] A list of transmission assets reaching end-of-life can be found in the Needs Assessment.

- **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.

6.2 Needs Identified

Table 6-1 summarizes the firm needs identified in this IRRP and are further discussed in the sections below. Note that the White Dog DS and Marathon DS station capacity needs occur in the long-term and are not further discussed in Section 7 since no firm recommendations are needed at this time.

Table 6-1 | Summary of Needs

Need	Need Description	Need Date
Fort Frances MTS Customer Reliability	Frequent loss of supply due to transmission outages; end-of-life assets at both Fort Frances TS and Fort Frances MTS	Today
E1C Operation	Supply capacity limitations with E1C operated normally closed; high voltage issues with E1C operated normally open	Today
Margach DS	Station step-down transformer capacity	2023
Crilly DS	Station step-down transformer capacity	2027
Kenora MTS	Station step-down transformer capacity	2029
White Dog DS	Station step-down transformer capacity	2032
Marathon DS	Station step-down transformer capacity	2038

6.2.1 Station Capacity Needs

6.2.1.1 Margach DS

Margach DS is approximately 10 km east of Kenora. Margach DS has an LTR of 10.4 MW and historical demand has been stable at just under 10 MW. As shown in Figure 6-1, Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied at Margach DS from a nearby CTS.

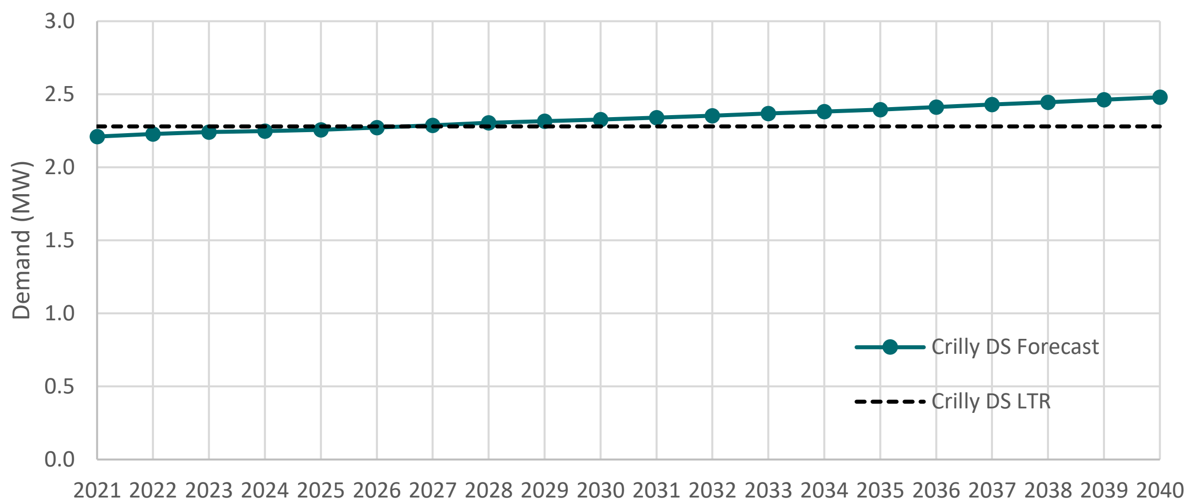


Figure 6-1 | Margach DS Forecast

6.2.1.2 Crilly DS

Crilly DS is a small (~2.2 MW LTR) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power when Sturgeon Falls is on outage. Furthermore, station equipment is nearing end-of-life and space constraints limit in situ refurbishment options.

Crilly DS is expected to reach capacity in 2027 due to incremental growth in the community as shown in Figure 6-2.

6.2.1.3 Kenora MTS

Kenora MTS serves the City of Kenora and has a LTR of 23.4 MW. Synergy North has received inquiries from potential customers seeking new connections, including a new 4 MW project, but no formal agreements have been finalized. While these projects have not been included in the forecast, a relatively high annual growth rate of 1.25% was applied to account for the high degree of development interest.

Figure 6-2 | Crilly DS Forecast

Kenora MTS is expected to reach capacity in 2029 as shown in Figure 6-3.

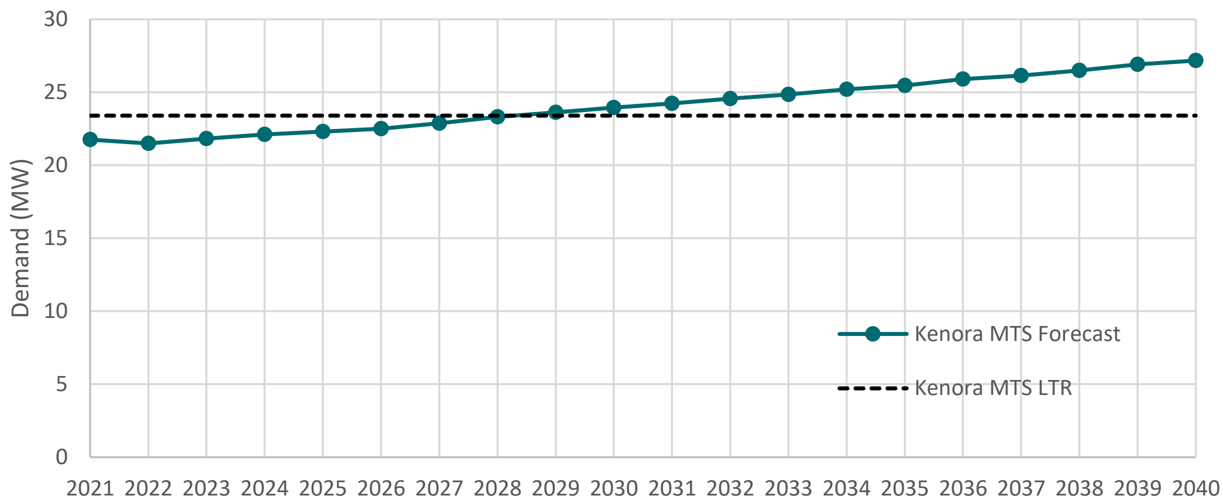


Figure 6-3 | Kenora MTS Forecast

6.2.1.4 White Dog DS

White Dog DS is located approximately 50 km northwest of Kenora and has a LTR of 2.9 MW. White Dog DS demand is expected to grow relatively quickly at an average rate of 1.3% annually due to growth in the community. White Dog DS is expected to reach capacity in 2032 as shown in Figure 6-4.

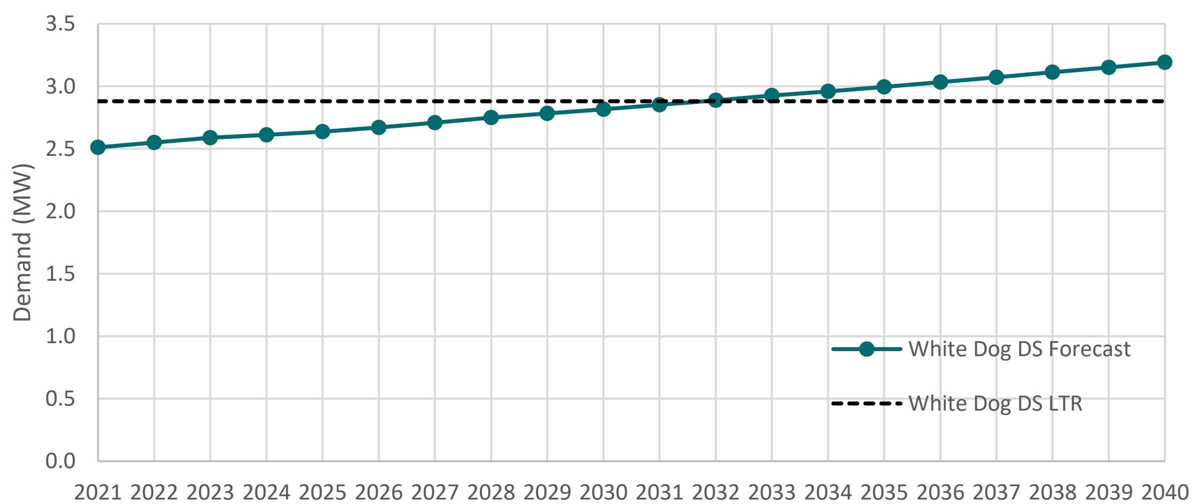


Figure 6-4 | White Dog DS Forecast

6.2.1.5 Marathon DS

Marathon DS serves the Town of Marathon and has a LTR of 10.4 MW. Growth is expected to be moderate and stable at an average annual growth rate of 0.9%. Marathon DS is expected to reach capacity in 2038 as shown in Figure 6-5.

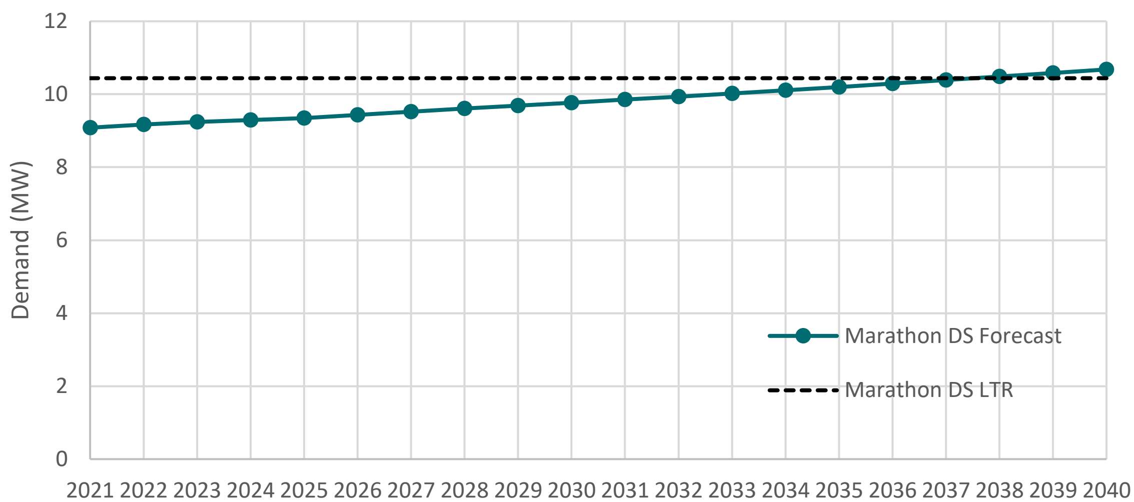


Figure 6-5 | Marathon DS Forecast

6.2.2 Fort Frances Customer Reliability Need

Fort Frances MTS, a step-down transformer station that supplies the Town of Fort Frances, is supplied via a single circuit 115 kV line, F1B, from the nearby Fort Frances TS. The two stations are located across the street from each other as shown in Figure 6-6. Fort Frances MTS experiences outages semi-annually to accommodate planned maintenance outages on F1B. Despite there being two step-down transformers at Fort Frances MTS, the single circuit supply configuration results in community-wide power outages since there is no redundant supply path to the station.

Historically, outage durations ranges from 4 to 8 hours and impact critical loads such as the regional hospital and local health clinics. Customers have raised concerns with interruptions to surgery schedules and vaccine spoilage due to the loss of refrigeration. Power outages also disrupt other commercial and residential customers. Customer surveys conducted by Fort Frances Power suggest that customers can tolerate short outages but are increasing sensitive to prolonged outages. Of the 10 causes of distribution system customer interruptions tracked by the Ontario Energy Board, loss of transmission supply accounts for 90% of Fort Frances Power's customer interruptions over the last 10 years.

Note that this customer reliability issue does not violate ORTAC load security and restoration criteria due to the relatively low total demand served at Fort Frances MTS. Fort Frances MTS serves approximately 16 MW of load today and is expected to grow to 18 MW by the end of the forecast horizon.[15] Load security criteria limits the total amount of demand interrupted with any single element out of service to 150 MW. For loads under 150 MW, load restoration criteria only require that service is restored within 8 hours. Despite compliance with ORTAC criteria, the Fort Frances MTS supply configuration is still highly disruptive for customers and could potentially be improved with relatively low-cost solutions given the proximity to Fort Frances TS.

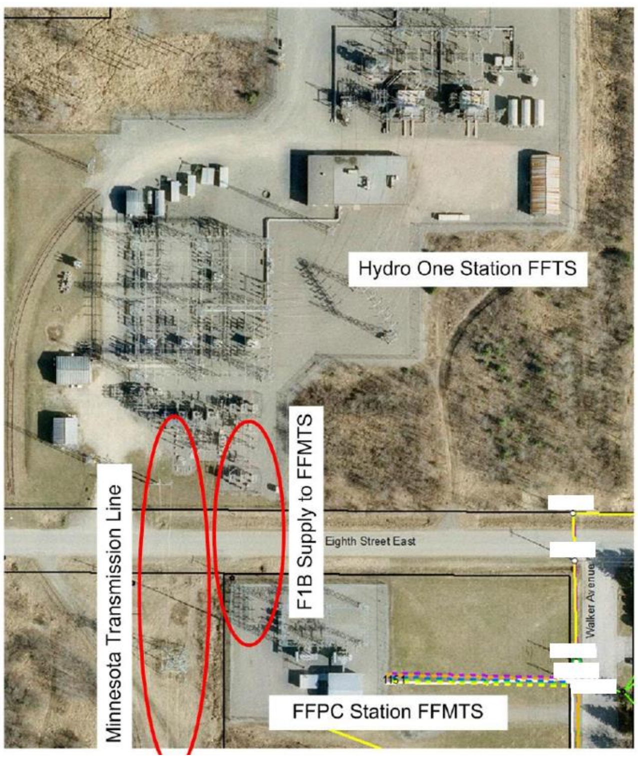


Figure 6-6 | Overhead view of Fort Frances TS (labeled as FFTS) and Fort Frances MTS (labeled as FFMTS)

[15] While there is currently no firm station capacity need within the forecast horizon, several potential large customers have approached Fort Frances Power that could quickly use up the remaining station capacity if they commit. This is further discussed in Section 6.3.2.

Fort Frances MTS station equipment is also aging with both transformers and most breakers dating from the 1960s and 1970s. The OEB's Asset Depreciation Study defines minimum, typical, and maximum useful life for a variety of electricity system assets. Apart from the main station breaker, which was replaced in 2019, all equipment at Fort Frances MTS is between its typical and maximum useful life. Furthermore, Fort Frances TS 115 kV breakers are also approaching end of life around 2027, which presents an opportunity to reconfigure the station to minimize supply interruptions for Fort Frances MTS.

6.2.3 E1C Operations and High Voltage Need

This section discusses the E1C operations with the new 230 kV Wataynikaneyap circuit, W54W, in service. W54W was first energized in Aug 2022. However, C3W, a short 30 m circuit between Wataynikaneyap TS and Pickle Lake SS, is still operated normally open. Therefore, W54W is not yet connected to the existing 115 kV circuits from Ear Falls TS to Pickle Lake SS and Musselwhite CSS (E1C, C2M, and M1M). C3W will be operated closed in the near future so that W54W can help support demand growth on C2M. This is consistent with the IESO's original recommended scope for the Wataynikaneyap Transmission Project in 2016.[16] For the purposes of this IRRP report, W54W being "in-service," refers to the final state with C3W closed. A single-line diagram of the area is shown in Figure 6-7.

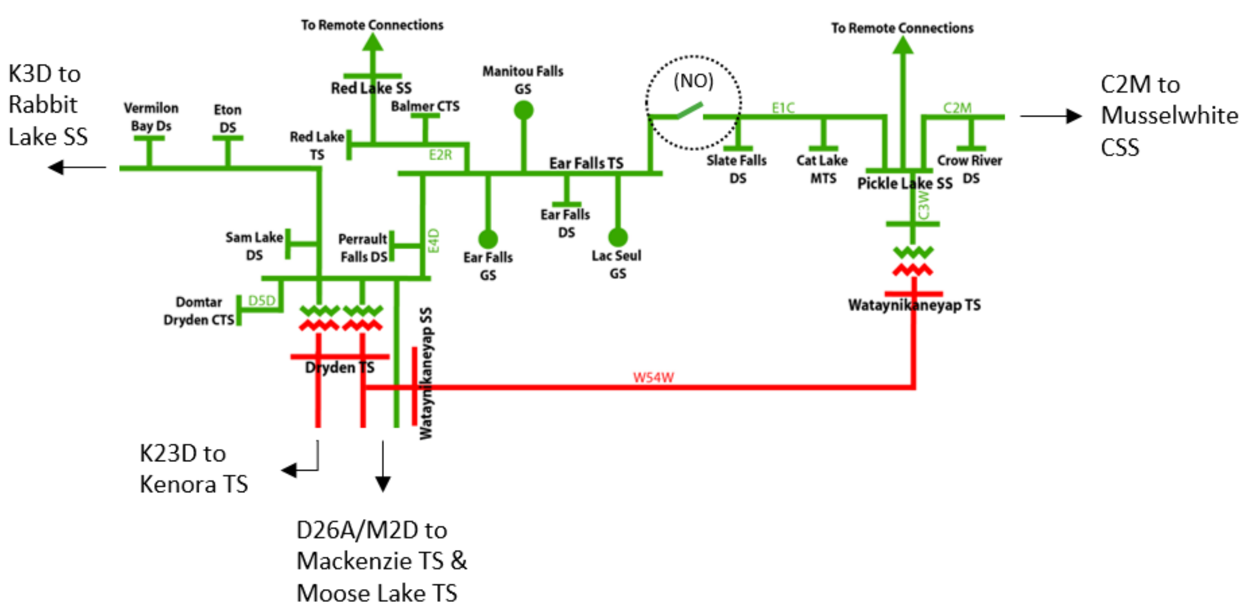


Figure 6-7 | Simplified Single Line Diagram of the Dryden and Pickle Lake Areas with Potential Normally Open Point

[16] The IESO's 2016 Recommended Scope of the new Line to Pickle Lake and Support Scope for the Remotes Connection Project is available on the Ontario Energy Board's priority transmission projects webpage.

With W54W in-service and connected to E1C via C3W, operating circuit E1C normally closed would result in a loop comprised of the E4D-E1C-W54W circuits. This arrangement would severely limit the transfer capability through E4D and W54W as documented in the 2016 W54W System Impact Assessment (SIA) report.[17] When operating with the E4D-E1C-W54W loop closed, loads in the Ear Falls area will remain connected through E1C via the 230 kV path following the loss of E4D. Post-contingency voltage collapse limits the E4D+W54W flow to 57 MW which is insufficient for supplying existing demand in the Ear Falls, Red Lake, and Pickle Lake areas. The SIA notes that E1C must be opened pre-contingency as a mitigating control action when flow exceeds 57 MW and that this could occur multiple times per day at existing demand levels.

Furthermore, the SIA found that with the E4D-E1C-W54W loop closed, the Manitou Falls and Ear Falls hydro generators would remain connected to the grid following the loss of E4D, which causes transient instability when the post-contingency flow on the E1C exceeds 30 MW. To ensure that transient stability of the generators is maintained, pre-contingency generation levels would need to be reduced such that post-contingency flow on E1C does not exceed 30 MW. This reduction of transfer capability on E1C not only violates ORTAC Section 4.1, which limits reduction in transfer capability that results from a new connection, but would bottle hydro-electric generation that is otherwise available to provide capacity to the Northwest system. Therefore, the SIA recommended that the E4D-E1C-W54W loop should be opened pre-contingency to prevent pre-contingency generation reductions.

Due to these documented issues, this IRRP reaffirms that E1C should be operated normally open once W54W is in-service with C3W closed. This configuration resolves the violations described above and the resulting system is adequate to serve forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas. This configuration is consistent with the recommended scope for W54W (which was referred to as the "Line to Pickle Lake") in the 2015 North of Dryden IRRP. Note that operating E1C normally open enables W54W to relieve E4D which allows W54W to serve the dual purposes of improving the load meeting capability of both the Pickle Lake and Ear Falls/Red Lake areas. This was an important consideration that contributed to the recommendation for W54W.

However, with E1C operated normally open, another problem emerges. High voltage violations (voltages exceeding 127 kV) occur post-contingency under light load conditions. High voltages occur on the line end open of E1C and either Pickle Lake SS or Ear Falls TS depending on where the open point on E1C is located. High voltage violations are less severe when opening E1C near Ear Falls TS compared to near Pickle Lake SS. When E1C is open near Ear Falls TS, the most critical contingency is the loss of one of the existing 20 MVar reactors at Wataynikaneyap TS. The high voltage violations can be addressed by installing an additional 10 MVar reactor at or near Pickle Lake SS. The post-contingency voltages at nearby stations with and without this

[17] The 2016 W54W System Impact Assessment report is available on the IESO's Application Status webpage by searching for SIA ID 2016-567.

additional 10 MVar reactor are shown in Table 6-2. The post-contingency voltages exceed 127 kV at the E1C open line end and Pickle Lake SS for the loss of the existing 20 MVar reactor at Wataynikaneyap TS. Post-contingency voltages are maintained below 127 kV with the additional 10 MVar reactor.

Table 6-2 | Post-contingency Voltages with and without Additional 10 MVar Reactor at Pickle Lake SS with E1C Normally Open at Ear Falls TS

Bus/ Station Name	Post-contingency voltage (kV)	Post-contingency voltage (kV) with additional 10 MVar Reactor at Pickle Lake SS
E1C LEO	**130.7**	123.3
Pickle Lake 115	**127.7**	120.6
Watay 115	126	120.1
Watay SS 230	238	235.5
Dinorwic 230	237.8	235.6
Mackenzie 230	244.8	244
Musselwhite 115	120	115.1

The IRRP recommends that the IESO and Hydro One collaborate in the Regional Infrastructure Plan refine the location of the E1C open point and associated reactive compensation devices required. The E1C open point can be fine-tuned to minimize high voltages. The open point on E1C should consider the location and condition of existing switches as well as their accessibility for restoration purposes should E1C be needed to partially restore loads following a W54W or D26A contingency.

Furthermore, the Regional Infrastructure Plan should consider the installation of a voltage-based automatic switching scheme for the reactors at Pickle Lake SS, Wataynikaneyap TS, and Dinorwic Jct similar to existing switching schemes at other stations across the Northwest region. Voltage-based automatic switching would improve the transmission system's operational flexibility, help manage high voltage conditions currently experienced across the Northwest and help reduce post-contingency high voltages to the acceptable continuous maximum voltage within 30 minutes. Potential interactions with the existing Northwest reactor switching scheme should be considered as this scheme is developed.

6.3 Potential Needs and High Sensitivities

No firm regional supply capacity needs were identified in the Northwest in either the reference or high forecast scenarios. However, most of the growth in the Northwest is driven by large mining and industrial development which can add large, incremental blocks of demand with minimal lead time that can quickly use up remaining supply capacity. Through engagement with development proponents and stakeholders, the Working Group identified two areas in the Northwest, the Dryden/Ear Falls/Red Lake area and the Fort Frances area, where there is particularly strong development interest and where the existing transmission system, although adequate for current forecast scenarios, may become constrained if all known proposed projects materialize.

For these two areas, the IRRP studied high growth sensitivities to quantify the load meeting capability and identify the limiting phenomena on the existing system. This was accomplished by adding hypothetical loads at existing stations/busses to simulate new developments and increasing the hypothetical load until a planning standards violation was observed.

As discussed in Section 4.1, the IRRP did not study local connection requirements of any individual project. The purpose of the high growth sensitivity studies is to quantify system limitations so that growth can be more effectively monitored between regional planning cycles and future planning activities can be initiated in a timely manner if growth materializes. Regardless of the availability of regional supply capacity identified in the IRRP, customers seeking connection may be subject to additional requirements and limitations specified in Customer Impact Assessments (CIA) or System Impact Assessments (SIA).

6.3.1 Dryden/Ear Falls/Red Lake Load Meeting Capability

The Dryden/Ear Falls/Red Lake area hosts significant mining activity today. It includes the 115 kV system supplied from the Dryden TS autotransformers, circuit K3D from Rabbit Lake SS, and M2D from Moose Lake TS. The recently completed 230 kV Wataynikaneyap Transmission Project line W54W will help relieve constraints on the 115 kV circuit E4D, once the recommendations in section 6.2.3 are implemented, and no incremental capacity needs are anticipated in this area based on the current demand forecast.[18]

The area's load meeting capability (LMC) is a function of three nested local constraints as shown in Figure 6-8:

(1) Supply to the Red Lake subsystem including: Red Lake TS, Balmer CTS, and Red Lake remote communities

[18] Consistent with the recommendation in Section 2.1.5 (E1C Operation and High Voltage) and the needs discussed in Section 6.2.3, the IRRP technical studies assumes that E1C will be operated normally open at Ear Falls TS.

(2) Supply to the Ear Falls subsystem including: Ear Falls DS, Perrault Falls DS, and the Red Lake subsystem described above

(3) Supply to the Dryden subsystem including: Sam Lake DS, Eton Ds, Vermilion Bay DS, Domtar Dryden CTS, and the Ear Falls subsystem described above

An implication of this "nesting" is that, depending on where new loads connect, they could contribute to one or more subsystem needs. For example, a load connecting close to Dryden would contribute to needs in the Dryden subsystem only, whereas a load connecting at Red Lake would contribute to potential needs in all three subsystems.

The supply capacity in these subsystems may be further constrained by bulk system limitations on the 230 kV supply to the area West of Thunder Bay. Bulk system limitations are outside the scope of regional planning and will be addressed by the Waasigan Transmission Line Project.

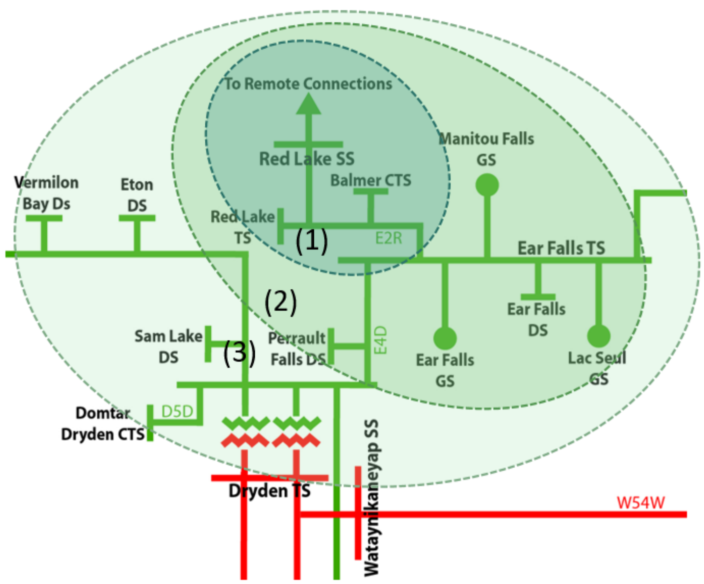


Figure 6-8 | Dryden/Ear Falls/Red Lake Nested Subsystems

Depending on which subsystem was being tested, the load meeting capabilities were derived by adding new hypothetical loads at Red Lake TS, Ear Falls TS, or the 115 kV bus at Dryden TS until a limiting phenomenon was encountered. The load meeting capabilities and the most limiting phenomenon or season for each subsystem is summarized in Table 6-3 and further described below. Note that, since the Northwest region is winter peaking, the IRRP forecast was developed for winter peak demand. However, since the Ear Falls and Red Lake subsystems can be thermally constrained, a summer peak forecast was also developed using the historical ratio between each station's summer and winter peaks.

Table 6-3 | Summary of Dryden/Ear Falls/Red Lake Load Meeting Capabilities

Subsystem	Load Meeting Capability	2032 Reference Peak Demand Forecast	2040 Reference Peak Demand Forecast
1. Red Lake	74 MW (summer thermal limitation)	61 MW summer peak	67 MW summer peak
2. Ear Falls	90 MW (summer thermal limitation)	67 MW summer peak	74 MW summer peak
3. Dryden	160 MW [19](summer/winter voltage decline)	129 MW winter peak	140 MW winter peak

6.3.1.1 Red Lake Subsystem

The Red Lake subsystem load meeting capability is limited in the summer by pre-contingency thermal overload of circuit E2R. The E2R continuous summer rating is 421 A which translates to a load meeting capability of approximately 74 MW.

The winter load meeting capability is higher than the summer capability. The winter load meeting capability is limited to 93 MW due to E2R pre-contingency thermal and voltage limitations. The winter E2R continuous winter rating is 528 A which translates to a load meeting capability of approximately 93 MW. 93 MW of load also causes pre-contingency voltage decline at Red Lake TS (i.e., voltages are under 113 kV). Note that the pre-contingency voltage limitation can be mitigated by installing appropriately sized voltage devices at the connection point of any new load. All load meeting capabilities described for the Red Lake and Dryden subsystems below assume that any new load will be accompanied by voltage devices to maintain adequate voltage performance at the point of connection.

Figure 6-9 below shows the Red Lake subsystem summer and winter peak demand forecast and associated load meeting capabilities.

The summer thermal limitation on E2R could be addressed by upgrading to higher rated conductors. There are several conductor options available with summer continuous ratings ranging from 590 A to 740 A.

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[19] This LMC is significant higher than the existing Dryden Area Inflow (DAI) limit in existing System Control Orders documentation. This difference is mainly due to topology changes (i.e. new W54W). The IRRP sensitivity study also assumes that new loads will connect with appropriate voltage control devices installed at the point of connection which alleviates previously documented low voltage issues.

Upgrading to 740 A conductors would result in a summer load meeting capability of approximately 130 MW. Note that upgrading to higher rated conductors would also necessitate replacing existing structures to increase their height so that the conductors can be operated at a higher temperature. Furthermore, Red Lake TS would need an alternative supply while work on E2R is carried out. Upgrading E2R would cost approximately $23M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[20] The cost difference between different conductor choices is relatively insignificant. Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

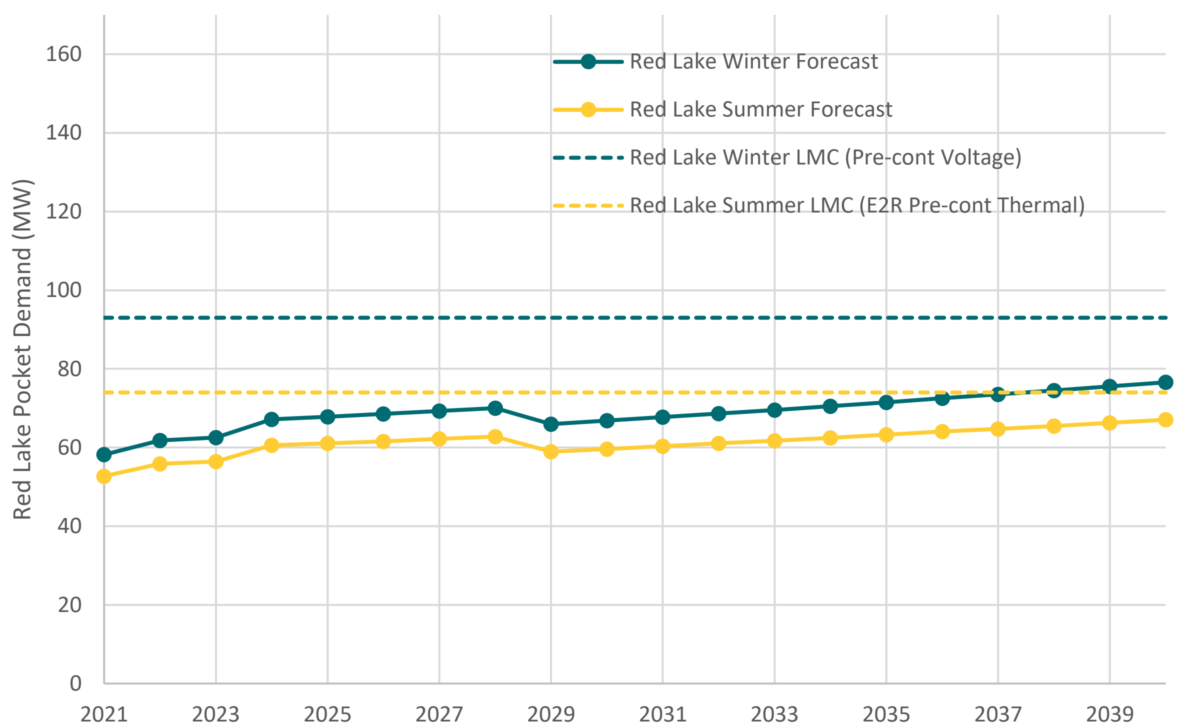

Figure 6-9 | Red Lake Subsystem Load Meeting Capabilities and Demand Forecast

E2R is approximately 75 years old. Hydro One anticipates that the average expected service life for the conductors is 90 years. The wood pole structures have a shorter expected service life at approximately 50 years. The end-of-life date for E2R will be based on actual asset conditions and no date has been determined for E2R as of 2022. If growth materializes, future planning

[20] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

studies should consider the cost of advancing E2R refurbishment as compared to alternatives such as local generation.

6.3.1.2 Ear Falls Subsystem

The Ear Falls subsystem load meeting capability is limited in the summer by E4D pre-contingency thermal overload. The E4D continuous summer rating is 410 A, which translates to approximately 72 MW. There is also a combined 18 MW of summer 98th percentile dependable hydro generation output from Ear Falls GS, Manitou Falls GS, and Lac Seul GS. Together the thermal capability and hydro generation results in a load meeting capability of approximately 90 MW.

Note that the winter load meeting capability is not expected to be limiting since it is significantly higher than the summer capability due to both the higher winter thermal rating of the circuit as well as higher dependable hydro generation output (approximately 64 MW of 98th percentile dependable hydro generation output).

Figure 6-10 below shows the Ear Falls subsystem summer demand forecast and load meeting capability.

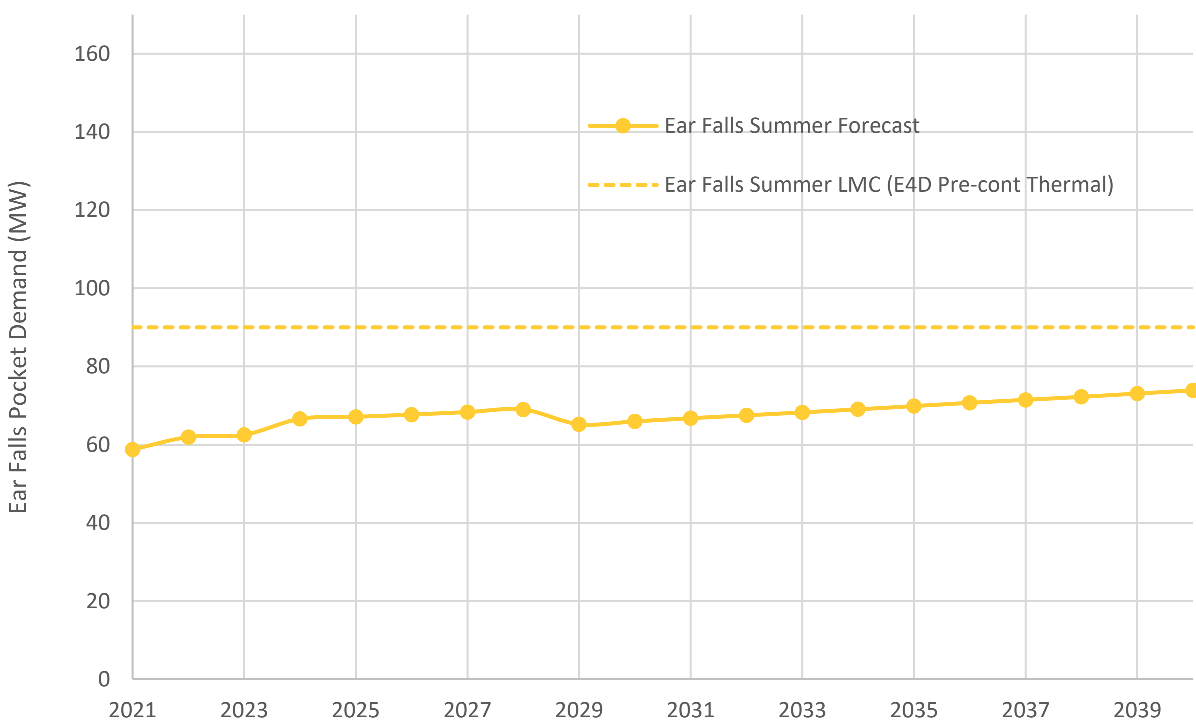

Figure 6-10 | Ear Falls Subsystem Load Meeting Capability and Demand Forecast

The summer load meeting capability for the Ear Falls subsystem can be increased to 130 MW by upgrading E4D with higher rated conductors (740 A summer continuous rating similar to conductors contemplated for E2R in the previous section). Upgrading E4D would cost approximately $35M (real $2022 overnight capital cost) based on high-level per km refurbishment costs for typical 115 kV wood pole lines.[21] Note this is a planning-level estimate (-50% to +100%); material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. E4D is approximately the same age as E2R; future planning studies should also consider the cost of advancing E4D refurbishment as compared to alternatives such as local generation.

6.3.1.3 Dryden Subsystem

The Dryden subsystem load meeting capability is limited to 160 MW in both the summer and winter due to post-contingency voltage decline following the loss of D26A. When total demand in the Dryden subsystem exceeds 160 MW, the voltage decline at Dryden TS will exceed criteria (10% decline) as shown in Table 6-4. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

Table 6-4 | Post-Contingency (D26A N-1) Voltage Change (160 MW Dryden Subsystem Total Demand)

Station	Pre-Cont Voltage	Post-Cont (Pre-ULTC) Voltage	Post-Cont (Post-ULTC) Voltage
Mackenzie TS	247 kV	242 kV	239 kV
Dryden TS	237 kV	216 kV	214 kV (10% decline)
Kenora TS	243 kV	229 kV	230 kV
Fort Frances TS	244 kV	229 kV	231 kV

Dryden TS post-contingency voltage decline will no longer be limiting once Phase 2 of the Waasigan Transmission Line Project is built since it will provide a redundant path from Mackenzie TS to Dryden TS parallel to D26A. Without Phase 2, the post-contingency voltage decline could be addressed by a dynamic voltage device at Dryden TS, but this was not further studied since the device requirements would depend on the connection arrangement and characteristics of future loads.

[21] The provided cost estimates do not include any associated upgrades that may be required to achieve the desired rating (e.g., raising poles, etc.) and should be viewed as high-level minimum costs.

Note that the D26A + K23D N-1-1 contingency results in more severe voltage decline but could be addressed by a load rejection scheme since special protection systems are permitted by ORTAC for outage conditions.

Figure 6-11 shows the Dryden subsystem summer and winter peak demand forecast and associated load meeting capabilities.

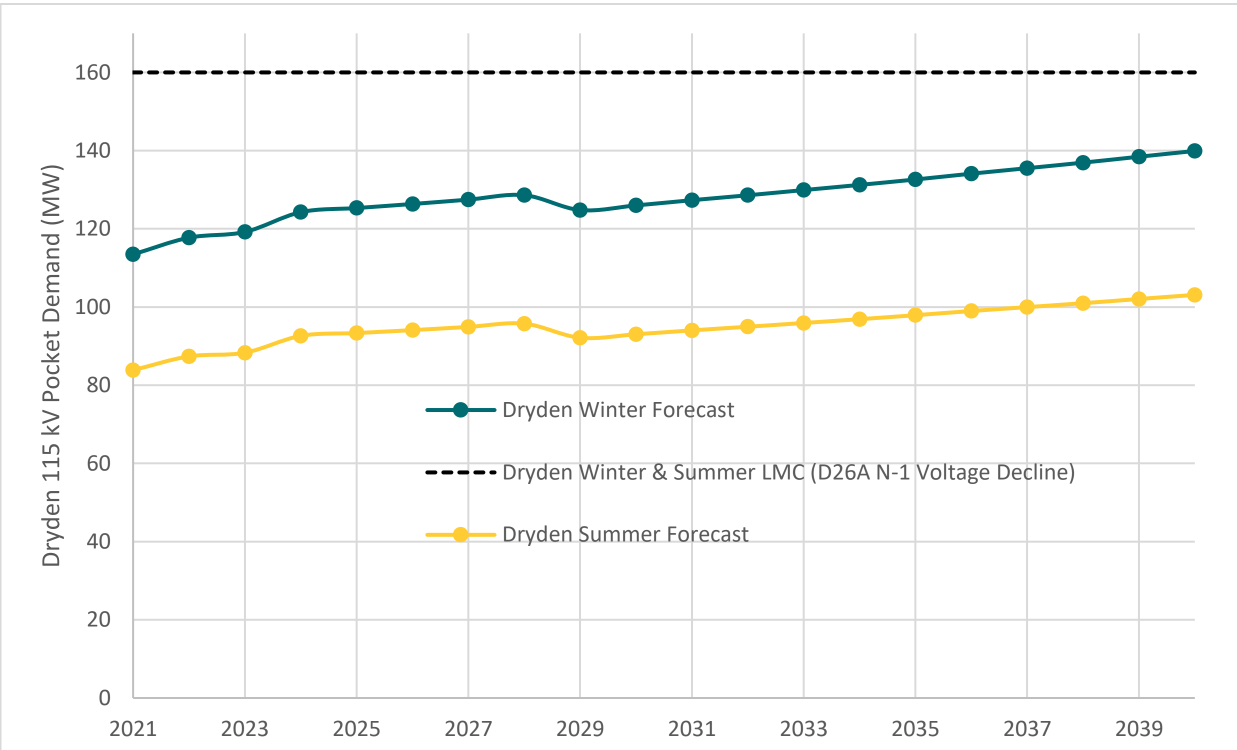

Figure 6-11 | Dryden Subsystem Load Meeting Capabilities and Demand Forecast

6.3.2 Fort Frances Load Meeting Capability

The Fort Frances area includes the 115 kV system supplied from the Fort Frances TS autotransformers and circuit K6F from Rabbit Lake SS as shown in Figure 6-13. For this high-growth sensitivity study, the Fort Frances area includes Fort Frances MTS, Burleigh DS, and a new hypothetical load connected directly to the 115 kV bus at Fort Frances TS. The stations connected to K6F do not materially impact the load meeting capability of the Fort Frances area.

Forecast demand in the Fort Frances area is relatively modest and is expected to grow from 21 MW today to 23 MW in 2040. However, the Working Group is aware of multiple inquiries from potential large new customers seeking connection in the Fort Frances area. Their combined load exceeds 100 MW but there is a high degree of uncertainty in whether their developments will proceed and where they may choose to connect to the grid. Some potential customers are also considering connection points in other parts of the province.

The Fort Frances load meeting capability is limited to 82 MW inclusive of approximately 3 MW of 98th percentile winter dependable hydro generation output from Fort Frances GS. This load meeting capability is the maximum total amount of load that can be served at Fort Frances MTS, Burleigh DS, and a new hypothetical load directly served on the Fort Frances TS 115 kV bus. It does not include load served on K6F. To achieve this load meeting capability, two new 25 MVar capacitor banks are assumed to be installed on the Fort Frances TS 115 kV bus to manage pre-contingency voltages. The load meeting capability is limited by post-contingency voltage decline on the Fort Frances TS 115 kV bus following the loss of F25A as shown in Table 6-5. The F25A contingency has a significant impact on 115 kV bus voltages because it removes one of the Fort Frances TS transformers (and the existing capacitor bank on its tertiary winding) by configuration. Note that for the purpose of deriving a conservative load meeting capability, a constant MVA load model was used as opposed to a voltage dependent load model.

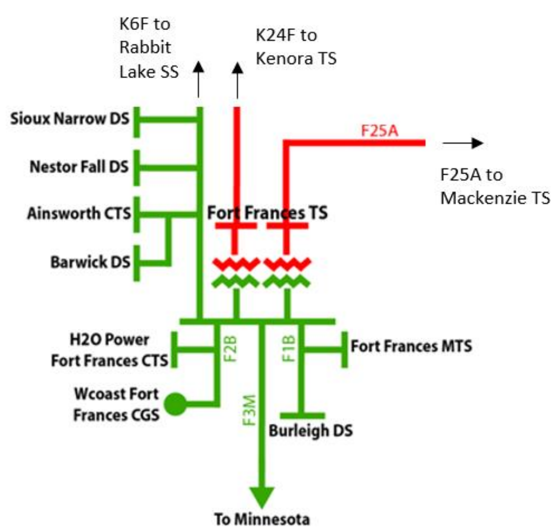

Figure 6-12 | Fort Frances Subsystem

Figure 6-13 below shows the Fort Frances subsystem winter peak demand forecast and associated load meeting capability.

Table 6-5 | Post-Contingency (F25A N-1) Voltage Change (82 MW Fort Frances Subsystem Total Demand)

Station/Bus	Pre-Cont Voltage	Post-Cont Pre-ULTC Voltage	Post-Cont Post-ULTC Voltage
Fort Frances TS (230 kV)	240 kV	234 kV	228 kV
Fort Frances TS (115 kV)	123 kV	110 kV (10% decline)	116 kV

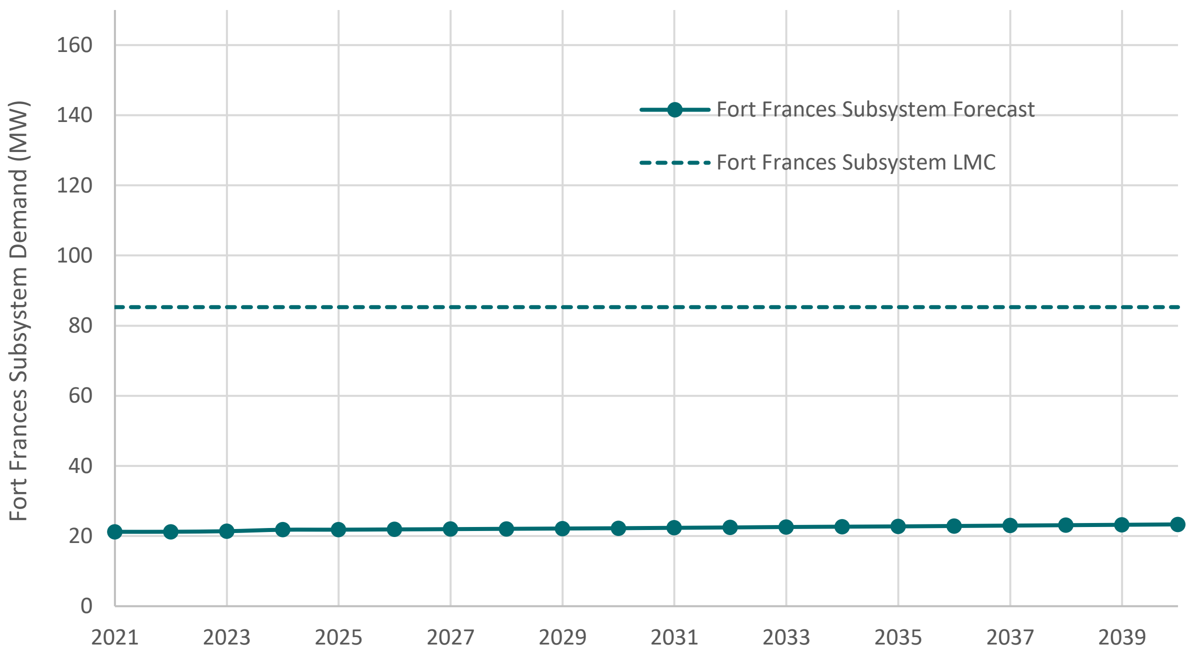

Figure 6-13 | Fort Frances Subsystem Load Meeting Capability and Demand Forecast

7. Options Considered and Recommendations

This section describes the options considered and recommendations to address the near- to medium-term needs identified in section 6. This section is organized as follows:

Section 7.1 describes the options considered for the Margach DS, Crilly DS, and Kenora MTS station capacity needs. This includes a discussion of how each station capacity need was screened for non-wires alternative suitability and, where there were promising non-wires opportunities, the options considered and financial analysis.

Section 7.2 explores configuration options to improve customer reliability at Fort Frances TS. These options will inform the Regional Infrastructure Plan where a final configuration will be chosen.

Note that the recommendation for the E1C operations and high voltage need can be found in Section 6.2.3 and will not be further discussed in this section.

7.1 Options and Recommendations for Station Capacity Needs

7.1.1 Methodology and Options Considered

There are two approaches for addressing station capacity needs:

- Build new infrastructure to increase station capacity. This is commonly referred to as a “wires” option and typically entails upsizing the existing station (e.g., replacing transformers with higher rated transformers or adding additional transformers) or building a new station to supply incremental demand growth. Wires options may also include modifications to or the addition of other power system equipment such as voltage regulation devices, switches, or breakers.

- Install or implement measures to reduce net peak demand to maintain loading within existing station capacity. This is commonly referred to as a “non-wires” alternative and can include options like energy storage, local distributed generation, demand response, conservation and demand management, or any combination of the above. Note that centrally delivered energy efficiency measures under the 2021-2024 Conservation and Demand Management framework are already included in the load forecast, as discussed in Section 5.2.2. Additional conservation and demand management can be considered as a non-wires alternative.

While wires options typically provide a step-change increase in capacity and are available in all hours, non-wires alternatives are more targeted and must account for the frequency and duration of the capacity need in addition to its magnitude. Therefore, identifying suitable technology types, sizing options, and simulating their discounted cash flows are significantly more complex for non-wires alternatives than wires options.

Non-wires alternatives are not suitable for all station capacity needs and there are often qualitative factors that rule out the use of non-wires alternatives. Before carrying out options analysis, a screening process is first applied to determine the suitability of non-wires alternatives for each need that considers the characteristics of the demand growth, the technical feasibility of non-wires alternatives to address the limiting phenomena, and any additional factors that would complicate or facilitate the implementation of non-wires alternatives. For stations where non-wires alternatives are suitable, the IRRP carries out options analysis as described below.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires alternatives are based on benchmark capital and operating cost characteristics for each resource type and size. Note that the error margin in cost estimates is significant at the planning stage (-50% to +100%); they are only intended to enable comparison between options during the IRRP. Material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs. Wires option costs can be reviewed in the Regional Infrastructure Plan before implementation work begins and the Working Group will revisit recommendations if cost estimates differ significantly. Actual non-wires alternative costs can also vary significantly from the benchmark estimates used in the IRRP depending on local market constraints at the time of implementation. The entity responsible for implementing the non-wires alternative (for station capacity needs, this will typically be the local distribution company) will only implement the alternative if it remains cost effective. Subsequent regional planning activities will be triggered if future costs differ significantly from those in the current IRRP.

For non-wires options, upfront capital and operating costs are compiled to calculate the levelized unit energy cost ($/MW-year). Similarly, an annual revenue requirement ($/year) is compiled for wires options. For each option, a discounted cash flow model is created which includes the levelized unit energy cost or annual revenue requirement as well as bulk system energy and capacity costs where applicable. Note that, in order to enable an apples-to-apples comparison, the discounted cash flow for the non-wires options includes a credit for the bulk system capacity value it provides. The discounted cash flow model for all options is compiled over the lifespan of the longest option considered (typically 70 years for wires options). The net present value (in 2021 CAD dollars) of these cash flows are the primary basis through which options are compared.

A list of the assumptions made in the economic analysis can be found in Appendix E.

7.1.2 Options and Recommendation for Crilly DS

Crilly DS is expected to reach capacity in 2027. Crilly DS is a small (LTR of ~2.2 MW) station supplied from a bus shared with Sturgeon Falls CGS, a small hydroelectric plant approximately 50 km west of Atikokan. This is a non-standard supply arrangement that results in annual outages to Crilly DS when the generator is undergoing maintenance. Diesel generation is currently used for backup power whenever Sturgeon Falls is on outage. Furthermore, the existing station equipment will reach end-of-life over the next ~10 years and space constraints limit in situ refurbishment options.

Non-wires alternatives are not suitable for Crilly DS due to three factors. First, non-wires alternatives will not be able to eliminate nor reduce existing reliance on backup generation. Load modifying non-wires alternatives (e.g., energy efficiency measures or demand response) could potentially reduce peak demand and overall energy consumption but, when transmission supply is interrupted due to Sturgeon Falls outages, they cannot replace the need for backup generation. Similarly, distributed energy resources can reduce peak demand below the station LTR but, during outages, the distribution system served by Crilly DS must still rely on backup diesel generation. Frequent reliance on backup diesel generation results in poor reliability and is technically challenging due to difficulties in staying connected and maintaining power quality when supplying loads on a long single-phase distribution line. The long-term solution for Crilly DS station capacity should ideally provide reliability on par with other single circuit supply stations (where regular supply interruptions are not required for generator maintenance outages).

Second, structures and equipment at Crilly DS are approaching end-of-life in the near future. While the specific end-of-life dates vary based on asset conditions, existing structures and equipment are expected to require refurbishment/replacement over the next 10 years. Even if non-wires alternatives can address overloads due to incremental growth above the current station capacity, the station must still be rebuilt/refurbished at end-of-life.

Third, Crilly DS serves a small pool of customers (approximately 500 homes and businesses) in a remote location. This customer pool is too small to cost-effectively target energy efficiency or demand response measures since the overhead costs will likely be prohibitive compared to the potential savings in deferred or upsized infrastructure. Furthermore, while voluntary energy efficiency and demand response programs can produce predictable results when applied over large populations, the demand savings when targeted to a small group of customers is unreliable.

Since non-wires alternatives are not suitable for Crilly DS, Hydro One Distribution is considering the follow wires options:

- Refurbish Crilly DS at its current location (and continue to rely on backup power during outages),

- Rebuild Crilly DS at a different location as a 115/25 kV HVDS (close to the existing station/supply point),
- Rebuild Crilly DS at a different location as a 230/25 kV HVDS (connected to F25A closer to the community served by Crilly DS), or
- Replace Crilly DS with 115:25 kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence).

The cost of these wires options ranges from $7.5-15M (including line work required for connection) and will address both the station capacity and end-of-life needs. Refurbishing Crilly DS at its current location is likely the least costly option but is undesirable due to the continued reliance on backup power. Furthermore, the incremental capacity that can be accommodated at the existing location may be limited due to the space constraints. Rebuilding Crilly DS as a full HVDS (either at 115 kV or 230 kV) would offer the best reliability and performance but also at the greatest cost. Replacing Crilly DS with a padmount transformer may be a more cost-effective option but there are still technical hurdles to be further investigated such as the ability for 115 kV protections to be accommodated within a padmount configuration.

Since non-wires alternatives are not suitable and there are no upstream supply capacity needs that require further regional coordination, the IRRP recommends that Hydro One Distribution conduct local planning, in coordination with the Regional Infrastructure Plan, to refine refurbishment/new station options identified in the IRRP with the goal of balancing reliability improvements and cost.

7.1.3 Options and Recommendation for Margach DS

Margach DS is expected to reach capacity in 2023 due to a large existing industrial customer seeking to be resupplied from a nearby CTS. Margach DS is approximately 10 km east of Kenora.

Non-wires alternatives are not suitable for addressing the Margach DS station capacity need due to the timing and magnitude of the demand increase. Resupplying the large industrial customer causes the forecast demand at Margach DS to jump by 40% from 2022 to 2023. Energy efficiency measures are typically only feasible if the demand exceeding station capacity is a small percentage of the total demand in each year. Similarly, historical zonal demand response auction data indicates that demand response is only feasible to reduce peak demand levels by single digit percentages. While distributed generation can technically be sized to accommodate any demand growth (within station short circuit and thermal limitations) this would functionally be the same as the new customer self-generating rather than seeking grid supply and is unlikely to be cost effective. The near-term timing of the demand growth is also problematic for implementing non-wires alternatives since many of the technical and regulatory barriers for implementing non-wires alternatives are still being tested.

The IRRP recommends that Hydro One Distribution install transformer fan monitoring which will increase the station capacity above forecast demand levels. Installing fan monitoring is an inexpensive method to increase the station LTR by enabling the use of higher thermal ratings on the existing transformers. The cost of installing fan monitoring is in the range of $1-1.5M compared to the cost of adding a new transformer which would be greater than $3M. Fan monitoring will increase the station capacity from approximately 10 MW today to 16 MW.

If additional capacity needs arise, a second transformer at the station which currently acts as a spare can be brought into service, but no recommendation beyond the fan monitoring is required based on the current forecast.

7.1.4 Options and Recommendations for Kenora MTS

Kenora MTS serves the City of Kenora and is expected to reach capacity in 2029 with a moderate annual growth rate of 1.25%. The station has an LTR of 23.4 MW and demand will exceed the LTR by approximately 4 MW by the end of the forecast horizon (2040).

Non-wires alternatives are promising for addressing the Kenora MTS station capacity need. The magnitude of the need relative to the total demand is moderate which makes targeting load modifying non-wires alternatives like energy efficiency and demand response feasible. The timing of the need is in the mid-term, so the forecast confidence is reasonably high while still having adequate lead time to demonstrate the efficacy of relatively untested non-wires alternatives and navigate technical and regulatory barriers. The timing of the need also means that lessons learned from the IESO’s York Region Non-Wires Alternative Demonstration Project can be leveraged for implementing non-wires alternatives for Kenora MTS.

The following subsections discuss the wires options for Kenora MTS, non-wires alternatives, and recommendations.

7.1.4.1 Wires Options

There are two high-level wires options:

- Expand Kenora MTS with an additional transformer and associated protections, control, and structures at a cost of approximately $5M. This can be accommodated on existing land owned by the distributor, Synergy North, within the station. This option assumes that feeder loads can be rebalanced and servicing these loads on existing distribution system infrastructure is possible.

- Construct a new substation located across the city from the existing station at a cost of approximately $30M. The new station would be supplied from Rabbit Lake SS.

The existing Kenora MTS station is located on the northern edge of the city. The proposed new substation would be located on the far west side of the city and, in addition to addressing station capacity needs, would provide substantial distribution system benefits by reducing the length of feeders required to reach customers and improving voltage and frequency regulation. The long feeders to the western parts of the system currently experience voltage and frequency issues especially during outages requiring parts of the distribution system to be resupplied from alternate feeders. Synergy North is also aware of significant development interest along the western outskirts of the city, but no formal agreements have been finalized. A new station would provide a supply point close to these customers and improve distribution system performance.

A new station would also provide a redundant transmission supply point that is connected to a different bus/breaker at Rabbit Lake SS than the existing station. If a new station is built, the distribution system could be designed with tie points and reclosers to enhance the overall reliability across Kenora.

The distribution system benefits above have only been qualitatively described in the IRRP. As discussed in the following subsections, the cost effectiveness of the non-wires alternatives may hinge on whether they can provide similar distribution system benefits as a new station. Future analysis by Synergy North should further quantify the value of these benefits.

7.1.4.2 Non-wires Alternatives

Three non-wires alternatives for Kenora MTS were identified and sized according to the characteristics of the hourly demand profile described in Section 5.6:

- A 4 MW gas generation facility (aero engine). The cost estimate for gas generation is based on the IESO's internal benchmark cost reports. To estimate its contribution to provincial system adequacy, its effective capacity was assumed to be 93% of its installed capacity, which is the lesser of its unforced capacity and the zonal capacity maximums reported in the 2021 IESO Annual Planning Outlook.[22]

- A 6-hour 4 MW (24 MWh) battery. The cost estimate for battery storage is based on data from the National Renewable Energy Laboratory. Note that local generation (e.g., wind or solar) was not required to complement the battery due to the relatively low energy requirement (i.e., the battery can be recharged from existing grid power when it is not needed).

[22] The 2021 Annual Planning Outlook is available on the IESO's Planning and Forecasting webpage.

- A combination of energy efficiency measures and demand response. The availability and cost of incremental energy efficiency measures (i.e., in addition to the conservation and demand management programs already included in the demand forecast) are based on the IESO's 2019 Conservation Achievable Potential Study[23]. The 2019 Achievable Potential Study and incremental energy efficiency savings for Kenora MTS are further described in Appendix E. Demand response costs are estimated from average capacity auction values from 2018-2021 for the Northwest zone.

The net present value (NPV) of each wires and non-wires alternative's cost is shown in Table 7-1. The NPV includes the levelized unit energy cost as well as bulk system energy and capacity costs and benefits associated with each option over a 45-year asset life (which is typical for station equipment).

Table 7-1 | Kenora MTS Wires and Non-wires Alternative Costs

Option	Cost NPV ($2021 Real)
Expand Kenora MTS	$4 M
New Station	$25 M
4 MW Gas Generation	$22 M[24]
24 MWh Battery Storage	$10 M[24]
Combination of Energy Efficiency and Demand Response	$1-9 M[25]

7.1.4.3 Recommendation

The cost of the non-wires alternatives generally falls between the cost of expanding the existing station and a new station (which also improves reliability and performance on the distribution system). Therefore, the decision to pursue non-wires alternatives versus traditional wires options rests on distribution system benefits that can be realized by each option. For example, battery storage can be sited on the distribution system such that it improves voltage regulation along lengthy feeders. If the value of the distribution system benefits is greater than the cost difference between the battery and station expansion, the battery may be the most cost-effective solution for ratepayers overall.

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[23] The 2019 Conservation Achievable Potential Study can be found on the IESO's website.

[24] Assumes full (unforced capacity) credit for system capacity value. Actual cost could be higher depending on the deliverability of the NWA resource.

[25] Cost ranges from $1-9 M depending on whether the energy efficiency measures are part of provincially cost-effective CDM (i.e implemented through the IESO's Local Initiative Program) or if they are incremental to provincially cost-effective CDM.

The technologies, regulatory framework, and protocols required to implement dispatchable non-wires alternatives (e.g., batteries, gas generation, or demand response) for the purpose of meeting local capacity needs are still being tested. The IESO's York Region Non-Wires Alternative Demonstration Project[26] is currently exploring market-based approaches to secure energy and capacity services from distributed energy resources (DERs) for local needs. There is a window of opportunity between today and 2029 when the Kenora MTS capacity need arises to leverage learnings from the York Region Pilot and further refine the procurement and operation of non-wires alternatives for Kenora MTS.

Since there are no upstream constraints on the transmission system requiring further regional coordination, the IRRP recommends that Synergy North lead further NWA analysis and refinement as part of local planning. Synergy North should monitor load growth at Kenora MTS to determine when a firm commitment for additional capacity is required and implement non-wires alternatives if they remain feasible and cost-effective. Furthermore, the IESO will consider Kenora MTS as a potential focus area for the Local Initiatives Program[27] under the 2021-2024 Conservation and Demand Management Framework. The IESO will collaborate with Synergy North in 2023 as further details for the next round of the Local Initiatives Program become available. In addition to the energy efficiency measures that may result from the IESO's Local Initiative Program, Synergy North may also use the Ontario Energy Board's Conservation and Demand Management Guidelines[28] to leverage distribution rates for non-wires alternatives.

7.2 Options for Improving Customer Reliability at Fort Frances TS

As discussed in Section 2.1.4, the IRRP will not make a specific recommendation for improving customer reliability since Fort Frances Power's roadmap for Fort Frances MTS is still under development. However, this section will document the options considered during the IRRP process and the IRRP recommends that Fort Frances Power and Hydro One continue to collaborate and select a preferred option in local planning.

The Fort Frances TS 115 kV station layout and connection to Fort Frances MTS is shown in Figure 7-1. The 115 kV side of Fort Frances TS is comprised of a 6-breaker ring bus with connections to the station's two autotransformers and circuits K6F, F3M, F2B, and F1B. Fort Frances MTS is currently connected to the L1-bus (which connects to F1B) and is physically located immediately adjacent to Fort Frances TS. Transmission outages to F1B and the L1 bus have accounted for 90% of Fort Frances Power's customer interruptions over the last 10 years. Therefore, Hydro One has proposed reconfiguration options with the goal of reducing Fort Frances MTS' exposure to transmission outages.

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[26] For more information on the pilot and latest developments, please see the York Region Non Wires Alternatives Demonstration Project engagement webpage.

[27] For more information on the Local Initiatives Program, please see the Save ON Energy Local Initiatives webpage and the 2021-2024 Conservation and Demand Management Framework webpage.

[28] More information about the Conservation and Demand Management Guidelines is available on the OEB's website (link).

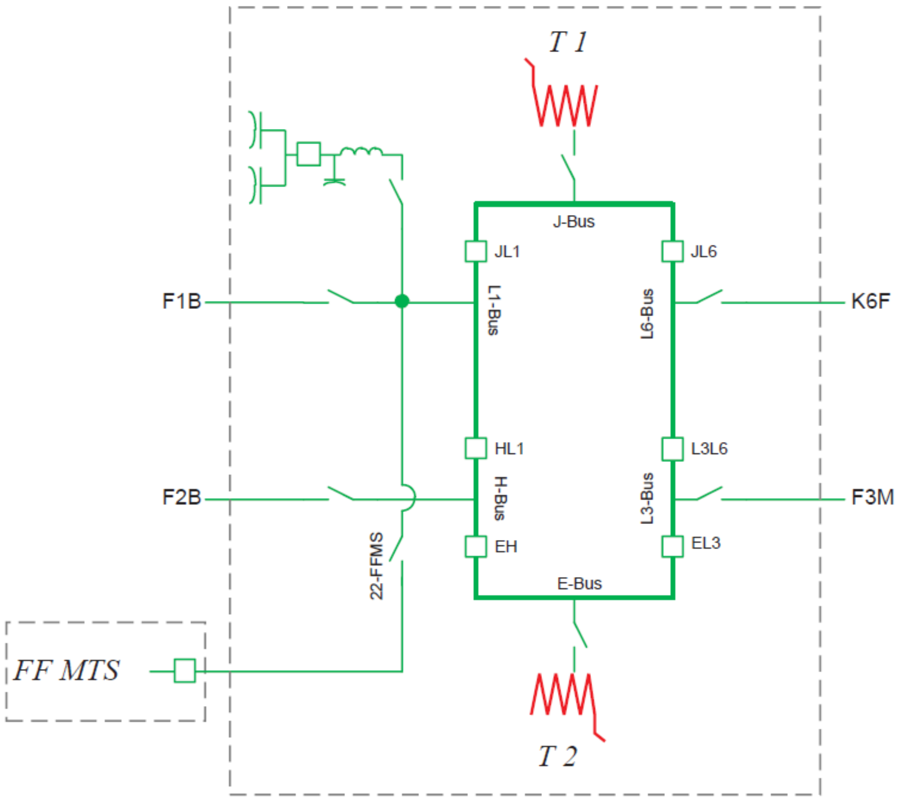

Figure 7-1 | Fort Frances TS 115 kV Single Line Diagram

The following options, in order of increasing complexity and cost, were contemplated:

- Replace the existing 22-FFMS air-break switch with an interrupter switch (still connected to F1B) and install a second interrupter switch to connect Fort Frances MTS to F2B. One of the two switches would be operated normally open, but the switches would allow Fort Frances MTS to be transferred between F1B and F2B to avoid any supply interruptions during planned outages on either of the two circuits or buses.
- Install a new 115 kV breaker on the L1 bus and move the Fort Frances MTS termination between this new breaker and the HL1 breaker. This would form a 7-breaker ring bus and Fort Frances MTS would have its own position separate from any other circuit.

- Install a second breaker at Fort Frances MTS and connect it to the H-bus via a new air-break switch. Since Fort Frances MTS already has two transformers, if both Fort Frances MTS breakers are normally closed, this configuration could provide fully redundant transmission supply. However, the feasibility of having both supply points normally closed is still being reviewed; a normally open point may be required to manage short circuit levels. If either the L1-bus or H-bus supply points needs to be operated normally open, this option would be functionally the same as the first option (but more expensive).

8. Supply to the Ring of Fire

The Ring of Fire is a remote area covering 5000 km^2 located 500 km north of Thunder Bay with rich deposits of critical minerals.[29] There is strong interest in developing mining activities in this area, however as it is located far from established infrastructure, it is currently without all-season road access or grid power supply. Transmission supply to the Ring of Fire was contemplated in the 2015 cycle of regional planning for Northwest Ontario. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study in parallel with the ongoing Northwest IRRP. This report provides an update on preliminary findings as of Q4 2022 including:

- Transmission supply options and high-level cost estimates;
- Key opportunities for alignment that should be considered in the decision to pursue transmission supply to the Ring of Fire as well as its routing and connection point;
- Avoided diesel system costs from connecting remote communities to the grid via a transmission line to the Ring of Fire; and
- Greenhouse gas reductions associated with connecting remote communities and Ring of Fire mines to the grid, as opposed to self generation.

Note that the decision to pursue transmission supply to the Ring of Fire ultimately lies with mining companies and remote communities as the direct beneficiaries of such a project, and with the provincial and federal governments to advance broader policy objectives. The purpose of the renewed Supply to the Ring of Fire study is to help inform government policy and potential customers seeking connection.

8.1 Background

A map of the Ring of Fire area and nearby features of interest are shown in Figure 8-1. Interest in developing the Ring of Fire has varied over the years and there is a high degree of uncertainty in the eventual mining sector electrical demand that may materialize. However, with the current focus on developing critical minerals to support decarbonisation, interest in developing the Ring of Fire area is growing.

[29] Ontario's critical mineral list can be found in the 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

In addition to potential mining loads, there are five off-grid Matawa First Nation communities in the vicinity of the Ring of Fire. These communities rely on diesel generation systems that are expensive to operate, produce environmental pollutants, and may constrain the communities' growth. Enabling grid supply for these communities is an important factor contributing to the overall rationale for transmission supply to the Ring of Fire. The transmission supply routing and connection point to the existing electricity system should also consider the significant potential for hydro generation in the area which may be able to connect to the grid via the transmission line to the Ring of Fire.

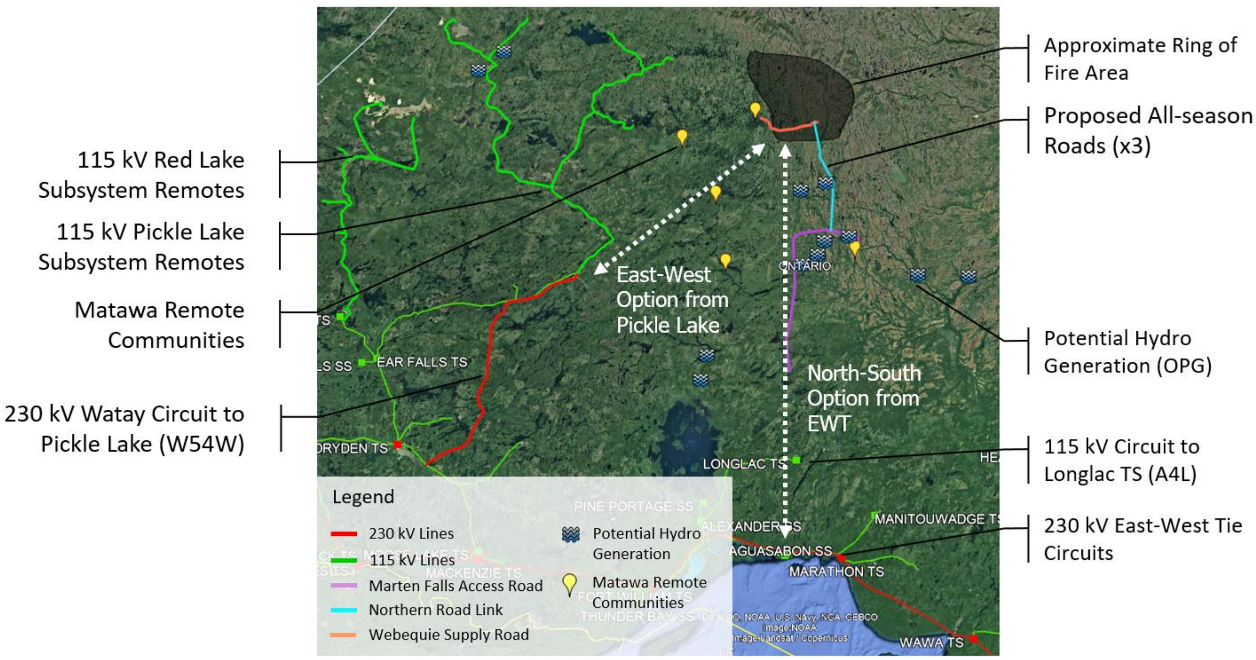

Figure 8-1 | Ring of Fire and Surrounding Area Map

Transmission supply to the Ring of Fire was contemplated in the 2015 North of Dryden IRRP and the 2016 Greenstone-Marathon IRRP. The North of Dryden IRRP outlined potential transmission supply options with the goal of connecting remote communities as well as serving mining electricity demand at the Ring of Fire if it were to materialize. This plan contemplated reinforcing the existing transmission system from the Dryden area to Pickle Lake and building a new transmission line from Pickle Lake to the Ring of Fire. The North of Dryden IRRP, in conjunction with the 2014 Remote Connection Plan, culminated in the indigenous-led Wataynikaneyap Transmission Project.

The Wataynikaneyap Transmission Project includes a new 230 kV line from Dinorwic Junction (near Dryden) to Pickle Lake as well as 115 kV transmission lines extending north of Pickle Lake and Red Lake to connect remote communities. The Matawa area remote communities chose not to participate in the Wataynikaneyap Transmission Project and no transmission lines were built from Pickle Lake to the Matawa communities or the Ring of Fire. This transmission supply option to the Ring of Fire is referred to as the East-West option in Figure 8-1.

The Greenstone-Marathon IRRP extended this analysis to consider potential cost optimization opportunities between new customers in the Greenstone area and remote communities/mines at the Ring of Fire. This entailed a North-South transmission supply option extending from the existing East-West Tie circuits northwards through Greenstone (which is electrically supplied from Longlac TS) and onwards to the Ring of Fire. The largest new customer in the Greenstone area at the time choose to self-generate instead of pursuing transmission supply and the North-South transmission supply option did not proceed.

To date, there have been no firm commitments from customers seeking transmission connection in the Ring of Fire area.

8.2 Policy Drivers and Demand Forecast

Enabling development in the Ring of Fire area is an important policy objective for the provincial government. Ontario's Critical Mining Strategy[30] identifies the Ring of Fire as a "priority project" and a "transformative opportunity for unlocking multi-generational development of critical minerals." The strategy also highlights the importance of Ontario's relatively clean electricity system for enabling development of lower-emissions mining compared to other jurisdictions.

The province has also expressed support for a "Corridor to Prosperity" comprised of three proposed all-season roads led by First Nations partners that connects to the existing highway system and extends northwards towards the Ring of Fire. These proposed roads include the Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link. The proposed roads are at various stages in their provincial and federal Environmental and Impact Assessments. Taken together, they would provide a continuous all-season transportation corridor to the Ring of Fire that would be necessary to facilitate mining development. Ontario has committed $1 billion to support these road infrastructure projects on the basis that federal contributions will match provincial commitments.

There is a high degree of uncertainty in terms of both the magnitude and timing of mining electricity demand at the Ring of Fire. The IESO's latest mining demand forecast includes approximately 30 MW of electricity demand associated with two proposed mining projects. The 2015/6 IRRP forecasts included up to 70 MW of demand at the Ring of Fire but some proponents have since walked away from their development plans. If transmission and

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[30] The 2022-2027 Critical Mineral Strategy is available on Ontario's Mining and Minerals website.

transportation infrastructure were developed, mining demand would almost certainly be much higher than currently forecast. As of January 2022, there are approximately 26,000 active mining claims held by 15 companies in the Ring of Fire. The IESO will continue monitoring development plans and intends to update the mining forecast in Q1 2023 to better capture Ring of Fire growth scenarios.

The five Matawa area remote communities have a total demand of approximately 4 MW today and are forecast to grow at 4% per year.[31] This forecast was last updated in 2019 and will be updated as new information becomes available.

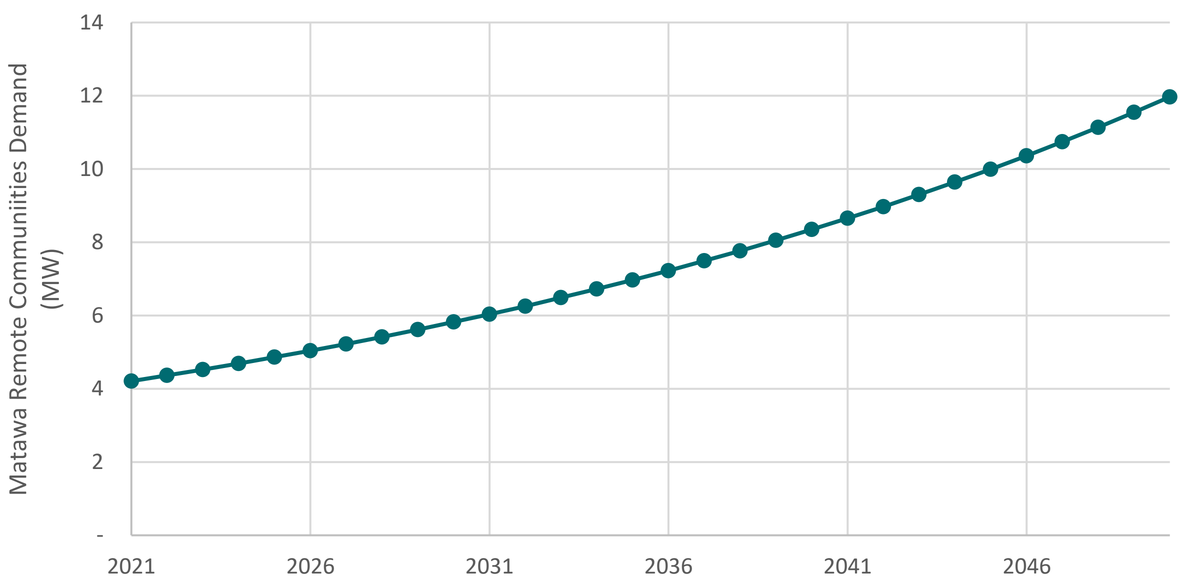

Figure 8-2 | Matawa Remote Communities Demand Forecast

[31]The forecast 4% growth rate reflects potential demand growth if the remote communities are grid connected and no longer constrained by diesel supply capacity.

8.3 Transmission Supply Options and Cost Estimates

As discussed in Section 8.1, at a high level, there are two transmission supply options to the Ring of Fire that could be pursued: a North-South option connecting to the East-West Tie circuits between Marathon and Thunder bay and an East-West option connecting to the new Wataynikaneyap TS near Pickle Lake. The conceptual electrical elements of each option are listed in Table 8-1. Note that at this stage, no detailed engineering design or routing work has been performed. The transmission options are presented here for discussion purposes and to facilitate high-level cost estimation (-50% to +100%).

The North-South option is estimated to cost between $860M and $1.08B while the East-West option is estimated to cost between $600M and $780M ($2022 real, overnight capital cost). The cost ranges reflect uncertainty in the final station configurations as well as in the per unit (km) cost of transmission lines which can vary depending on the technology type and geography. These cost estimates are not inclusive of step-down transformer stations at the loads themselves nor reactive compensation devices which will depend on the magnitude of the demand. Note that material and labour costs have increased rapidly over the COVID-19 period and there is a high degree of uncertainty in future costs.

Table 8-1 | Ring of Fire Transmission Option Conceptual Elements

Transmission Supply Option	Element #	Description	Length (km)	Cost ($2022 real)
North-South	1	230 kV single circuit line from East-West Tie circuits to Longlac	120	$170-215M
	2	New stations at East-West Tie connection point[32] and Longlac (to enable connection to A4L);	N/A	$115-125M
	3	230 kV single circuit line from Longlac to McFaulds Lake; roughly parallel to proposed roads	410	$575-740M
East-West	1	230 kV single circuit line from Wataynikaneyap TS near Pickle Lake to McFaulds Lake; roughly along route envisioned in the 2014 Remote Connection Plan	370	$580-745M
	2	Wataynikaneyap TS modifications	N/A	$20-30M

[32] Connecting the Ring of Fire line directly to East-West Tie lines between Lakehead TS and Marathon TS minimizes costs since it is the closest 230 kV supply point to the Ring of Fire. However, connecting to only one (or any subset) of the four parallel East-West Tie lines will unbalance flows between Marathon TS and Lakehead TS and may decrease the overall transfer capability of the East-West Tie. Future studies should weigh the costs and benefits of connecting to either Lakehead TS or Marathon TS versus a new junction and/or switching station on the East-West Tie.

While the East-West option is less expensive than the North-South option, it would provide less incremental capacity to supply load and would also increase exposure to outages. The load meeting capability for a radial expansion of the transmission system like the Ring of Fire is typically constrained by thermal, voltage, and load security limits. The thermal rating of a 230 kV single circuit line is unlikely to be constraining; as an example, a single East-West Tie circuit has a continuous rating of approximately 320 MW in the summer and 390 MW in the winter. This far exceeds the current known mining and remote community demand forecast. Voltage limits can be managed by installing voltage regulation devices at the loads and can be sized according to the expected demand, however this would add incremental cost and operational complexity. Load security limits, however, may become the most limiting factor depending on future mining developments.

Ontario Resource and Transmission Assessment Criteria (ORTAC) Section 7.1 load security criteria specifies the maximum amount of load that can be interrupted after certain contingencies. For the loss of a single element (i.e. single circuit supply to the Ring of Fire), no more than 150 MW may be interrupted. This limits the total load served on the North-South option to 150 MW. The East-West option is connected downstream of the new single circuit Wataynikaneyap line (W54W). The total load served by W54W is also limited to 150 MW including the all existing loads and their growth, new mining customers along W54W, and the Ring of Fire and Matawa communities. Existing load served on W54W totals approximately 45 MW today and is expected to grow to 80 MW by 2040. While the remaining room is sufficient for serving the currently forecast demand at the Ring of Fire (30 MW mining plus Matawa area communities), it leaves relatively little room to accommodate additional development. Furthermore, the IESO is aware of several additional mining projects potentially seeking connection along W54W. While these projects are not yet certain enough to be included in the IRRP reference forecast, they could significantly reduce the available capacity for growth at the Ring of Fire.

While not addressed by ORTAC criteria, another consideration is the level of exposure to outages. The East-West option would involve connecting the Ring of Fire and Matawa communities to a radial system that already spans several hundred kilometers of transmission lines (W54W and D26A). Each time any part of this system is faulted (e.g., in an electrical storm or fire), the whole system is removed from service until the fault can be addressed. By comparison, the North-South option can be connected to the East-West Tie (or nearby station) which are more robust and has redundant supply.

Due to the uncertainty in future mining developments, it is too early to rule out the East-West option at this time. However, the potential capacity constraints and customer reliability impacts related to the East-West option should be considered when selecting a preferred transmission option. The next section discusses opportunities for alignment and further considerations that may impact the preferred transmission option.

8.4 Opportunities for Alignment

A decision to pursue transmission supply to the Ring of Fire, and decisions on its preferred routing, should consider alignment with four opportunities in addition to supplying mining demand at the Ring of Fire:

- Supplying Matawa Remote Communities
- Enabling potential hydro generation
- Improving supply to Longlac
- Co-locating with transportation corridor

These opportunities for alignment are discussed in turn below.

8.4.1 Supplying Matawa Remote Communities

There are five Matawa indigenous remote communities in the vicinity of the Ring of Fire:

- Webequie
- Nibinamik
- Neskantaga
- Marten Falls
- Eabametoong

These communities were previously identified as economic for grid connection in the 2014 Remote Connection Plan but elected not to participate in the Wataynikaneyap Transmission Project. The 2014 Remote Connection Plan found that it was more cost-effective to supply the communities via a single circuit 115 kV transmission line (either from Pickle Lake or the East-West Tie circuits) than continued reliance on off-grid diesel generation systems. Transmission supply to the Ring of Fire could also enable connection of the Matawa remote communities. Both the North-South and East-West transmission options would serve this purpose. Updated potential avoided diesel generation system costs are discussed in Section 8.4.2.

Note that the decision to pursuing grid connection is up to the communities. The IESO will continue to engage with the Matawa communities to inform future studies. Furthermore, grid connection of remote communities does not preclude local energy projects such as the installation of distributed generation and storage. The IESO continues to support broad equitable participation in Ontario's energy sector through its Energy Support Programs including the Indigenous Energy Projects (IEP) Program[33] which provides funding support to First Nation and Metis communities to assess and develop energy projects and partnerships.

8.4.2 Enabling Hydro Generation

In Jan 2022, the Ontario government asked Ontario Power Generation to examine opportunities for new hydroelectric development in northern Ontario. New hydroelectric generation could address the growing long-term electricity needs forecast for the province, with the potential for economic benefits for local and Indigenous communities in the north. Ontario Power Generation has shared this work with the Ministry of Energy and the IESO so that it can be considered as part of the IESO's work towards developing an achievable pathway to zero emissions in the electricity sector. Development of transmission supply to the Ring of Fire should consider the connection of potential hydro generation in the area.

There is significant hydroelectric generation potential in the vicinity of the Ring of Fire. Due to the geographic distribution of these potential generation facilities, the North-South transmission option is better suited than the East-West option to connect these facilities on the way to the Ring of Fire. Furthermore, the North-South option connects to a more robust point in the bulk transmission system which may result in fewer deliverability constraints and lower overall losses. The Ring of Fire North-South transmission line is not necessarily the optimal connection point for potential hydro generation near the Ring of Fire. Other connection options, to Pinard TS for example, may reduce the overall bulk system reinforcements needed to deliver the hydro generation capacity to southern Ontario. However, connecting to the Ring of Fire transmission line could significantly reduce the length of connection lines required for these potential hydro generators and future studies should consider the synergies between Ring of Fire transmission supply and enabling the connection of potential hydro generation.

8.4.3 Improving Supply to Longlac

The existing radial 115 kV circuit, A4L, to Longlac TS is near capacity and customers have expressed concern about poor reliability due to long and frequent outages. While no firm growth plans or new customer connection requests were received during this IRRP, there continues to be a high degree of interest for mining and industrial developments in the Greenstone and Geraldton areas supplied by A4L. There are also existing customers along A4L who have elected to self-generate rather than connect to the transmission system due to capacity constraints.

A4L refurbishment is underway and distance-to-fault relays have been installed which should decrease the frequency of outages and improve restoration times. However, these improvements do not increase the load meeting capability on A4L and, as with many other areas in the Northwest region, growth can materialize quickly.

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[33] For more information, please visit the Indigenous Energy Projects Program webpage.

The North-South transmission option passes directly by Longlac TS and could help increase capacity and provide a secondary supply path to further improve reliability. The North-South option conceptual elements in Table 8-1 includes a 230/115 kV transformer station at Longlac for this purpose. Note that the East-West option is not suitable for reinforcing Longlac.

8.4.4 Co-locating with Transportation Corridor

The proposed Marten Falls Community Access Road, Webequie Supply Road, and Northern Road Link will provide a continuous all-season transportation corridor to the Ring of Fire. While detailed routing has not yet been performed, the North-South transmission option is well aligned with the proposed roads. The line length determined for the North-South option in Table 8-1 assumes that the transmission corridor runs parallel to the proposed roads wherever possible but the potential cost savings associate with colocation has not been factored into the transmission cost estimate yet. This likely overestimates the cost of the North-South transmission option compared to the East-West option; future studies should conduct more detailed engineering design and routing analysis to better quantify the benefits of colocation.

Co-locating linear infrastructure is consistent with provincial policy as articulated in Section 1.6.8 of the 2020 Provincial Policy Statement[34] and may help reduce environmental impacts. The roads would also provide easier access to the transmission line which could simplify construction as well ongoing operation and maintenance. Note that there are no proposed all-season roads along the East-West option route.

8.5 Avoided Matawa Communities Diesel System Costs

The Matawa remote communities are currently supplied by remote on-site diesel generation which is costly to operate. Up to 70% of the fuel must be flown in when winter roads are not available contributing to high costs and increased emissions from fuel transport. The costs of supplying electricity from remote diesel generation systems versus the grid over the first 20 years of transmission connection are shown in Figure 8-3. The net present value of remote diesel generation costs is estimated to be $446M over this period, while serving the same load from the provincial grid is estimated to be roughly $35M.[35] These net present values are expressed in real dollars in the year when transmission connection is hypothetically brought in-service. For the purpose of this assessment, it was assumed that transmission connection occurs in 2030 given the typical 7-year lead time of new transmission projects.

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[34] The 2020 Provincial Policy Statement can be found on the Ontario government's Land Use Planning webpage.

[35] The cost of serving loads on the provincial grid is solely based on the system's marginal cost of energy. It does not include cost of transmission connection itself. Connecting remote communities is one of multiple potential benefits (other benefits include supplying mining loads and enabling hydro generation) that contribute towards a rationale for transmission supply. The cost of transmission supply should be compared against this full suite of benefits.

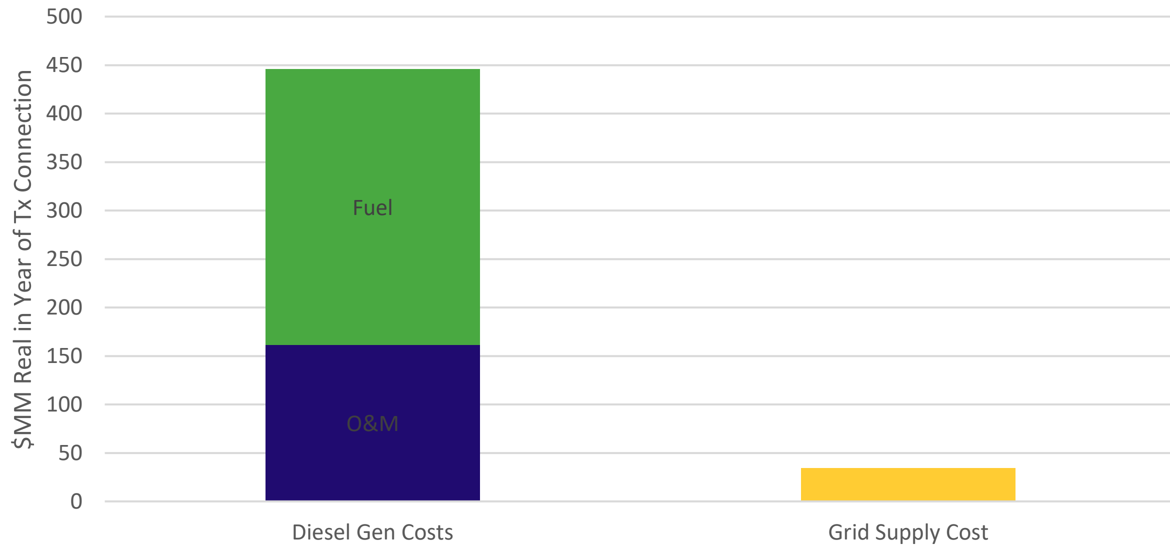

Figure 8-3 | NPV of Electricity Supply Costs from Diesel Generation versus the Provincial Grid for Matawa Remote Communities over the First 20 Years of Grid Connection

The cost of continuing to supply electricity to the remote Matawa communities by local diesel generation was estimated using the IESO's internal fuel forecast and aggregated cost data for remote communities served by Hydro One Remote Communities.[36] Generally speaking, economic and cost assumptions were consistent with the 2014 Remote Connection Plan adjusted for inflation. The cost of supplying electricity from local diesel generation is comprised of two components:

- Fuel costs including the cost for the fuel itself, winter road/air transportation, and the cost of carbon;
- Operating and maintenance costs estimated from historical revenue requirement and rate application regulatory submissions as a percentage of fuel costs.

[36] Not all Matawa communities are served by Hydro One Remote Communities. For communities served by Independent Power Authorities for which cost data was not directly available, system costs were estimated based the size of their load and Hydro One Remote Communities' system costs.

Of the $446M net present value, $284M is associated with fuel costs and $162M with operating and maintenance costs. Note that this cost estimate does not include the capital costs associated with expanding existing diesel systems to meet future capacity growth. This enables an apples-to-apples comparison with the cost of grid electricity which also did not include the incremental resource capacity cost of serving the newly connected remote communities. Furthermore, since the incremental capacity requirement is dependent on the year in which transmission connection occurs and the system needs/market conditions in the period following grid connection, capital costs associated with this capacity cannot be accurately calculated today. Future studies should refine the consideration of capacity costs when there is more certainty on when transmission supply will proceed.

The cost of serving Matawa remote communities should they be connected to the provincial electricity grid was based on the system marginal cost forecast in the 2021 Annual Planning Outlook.

8.6 Avoided Greenhouse Gas (GHG) Emissions

Avoided GHG emissions was estimated for the Matawa communities and the future mining load through the comparison of emissions on the electricity system (consistent with the 2021 Annual Planning Outlook emission rate per MWh) versus diesel generation for remote communities and natural gas generation for mining loads.[37]

The GHG reduction associated with connecting Matawa communities depends on the forecast demand levels and growth rate when transmission connection occurs. Consistent with the diesel system cost savings estimates in the previous section, transmission connection was assumed to occur in 2030. On average, over the first 20 years of transmission connection (i.e. 2030-2049), GHG reductions are expected to be approximately 27,000 tCO2e per year.

The GHG reduction associated with mining loads depends on the amount of demand that materializes. As discussed in Section 8.2, there is a high degree of uncertainty in terms of both the magnitude and timing of this demand. For illustrative purposes, if 30 MW of demand materializes (consistent with demand from known projects), GHG reductions would total 68,000 tCO2e per year. If 70 MW of demand materializes (consistent with demand from the 2015 IRRP forecasts), GHG reductions would total 160,000 tCO2e per year. The true avoided GHG emissions associated with connecting mining loads instead of on-site generation could be much higher given the large number of active mining claims in the Ring of Fire.

[37] The natural gas generation was assumed to be a combined cycle gas turbine (CCGT) facility with a heat rate of 7.265 MW/MMbtu and a natural gas emission intensity of 53.157 kgCO2e/MMbtu. For diesel generation emissions, the Hydro One Remote Communities fleet average generator efficiency and a diesel emission intensity of 75.22 kgCO2e/MMbtu was assumed.

8.7 Next Steps

The sections above provide an overview of preliminary findings to date of the Supply to the Ring of Fire Study and highlights some areas of uncertainty that will require further investigation. The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope, timing, and engagement process will evolve with government policy direction. The IESO will share updates with the Working Group to inform upcoming regional planning activities such as the Regional Infrastructure Plan.

9. Engagement

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

9.1 Engagement Principles

The IESO's engagement principles[38] help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

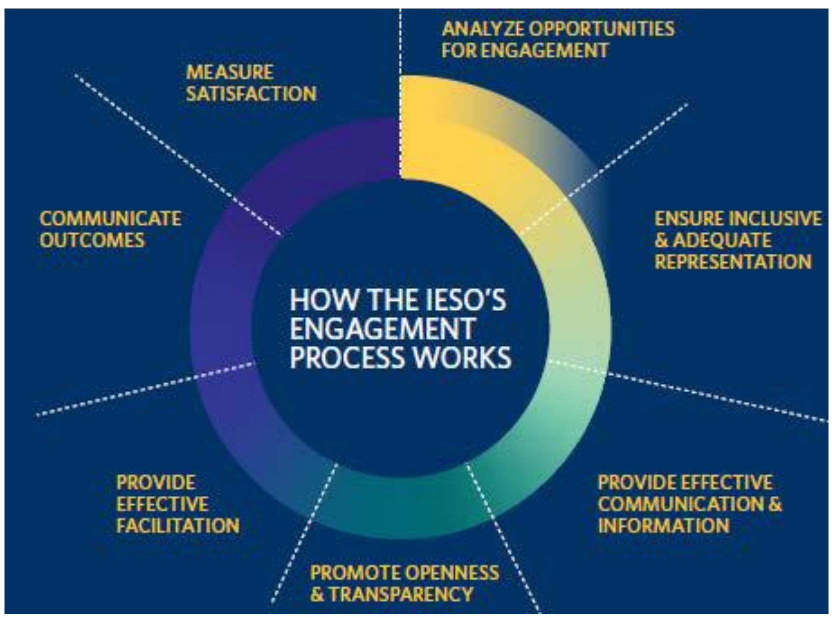

Figure 9-1 | IESO's Engagement Principles

38 https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

9.2 Creating an Engagement Approach for the Northwest

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

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable broad participation, using multiple channels to reach audiences; and
- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

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

- A dedicated webpage[39] on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email and through the IESO weekly Bulletin;
- Public webinars;
- Targeted discussions sessions;
- Face-to-face meetings; and
- One-on-one outreach with specific communities and stakeholders to ensure that their identified needs are considered (see Sections 9.4 and 9.5).

[39] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-Northwest-Ontario

9.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this round of planning, leveraging existing relationships built through the previous planning cycle. This started with the Scoping Assessment Outcome Report for the Northwest region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues to announce the commencement of a new regional planning cycle and invite interested parties to provide input on the Northwest Scoping Assessment Report before it was finalized.

Feedback was received and focused on the need to ensure that municipal energy planning, including the need to recognize climate change priorities, as well as economic development and industrial growth (including forestry and mining) were in scope of the development of the IRRP. In addition, reliability remained a paramount concern within this region. Along with a response to the feedback received, the final Scoping Assessment was posted on January 13, 2021, which identified the need for a coordinated regional planning approach across the Northwest region – particularly important since the previous planning cycle targeted regional plans within five identified sub-regions.

Following the finalization of the Scoping Assessment, outreach then began with targeted municipalities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to IESO subscribers of the Northwest planning region as well as all identified municipalities and Indigenous communities to ensure that all interested parties were made aware of this opportunity for input. Four public webinars were held at key stages during the IRRP development to give interested parties an opportunity to hear about progress and provide comments on various components of the plan.

All these engagement sessions received strong participation with a cross-representation from stakeholders and community representatives. Feedback was received as a result each engagement meeting which was considered in each of the stages in the IRRP development.

The public webinars invited input on:

1. The draft engagement plan, the electricity demand forecast and the early identified needs to set the foundation of this planning work.

2. The defined electricity needs for the region and potential options to meet the identified needs.

3. The analysis of options and draft IRRP recommendations.

In addition, three targeted discussions were held virtually to uncover specific feedback from communities and stakeholders on the following three topics:

1. Customer Reliability Concerns
2. Emerging Local Initiatives
3. Emerging Electricity Needs in the North of Dryden Area

Comments received during this engagement focused on the following major themes:

- Given the large geographic area for this planning region, consideration throughout the engagement should be given to targeted discussions to address local reliability and priorities. Education and support should be available to enable purposeful engagement for all interested parties
- Consideration in the demand forecast should be given to local developments, growth plans and climate change goals (i.e., electrification) – particularly in communities where capacity may be limited
- Non-wires alternatives should be considered to meet needs and, in particular, climate change priorities; existing resources in the region should be considered where contracts are due to expire
- Due consideration should be given to providing capacity for new commercial and industrial (mining and forestry) growth as well as electrification of existing industry
- Opportunities for future proponents to leverage existing partnerships or create new relationships among local and Indigenous communities to have due consideration of priorities and provide business prospects, where possible

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

All interested parties were kept informed throughout this engagement initiative via email to Northwest region subscribers, municipalities, and Indigenous communities as well as the members of the Northwest Regional Electricity Network.

Based on the discussions through the Northwest IRRP engagement initiative and broader network dialogue, there is a clear interest to further discuss the potential for development of the mining sector in this region and to look for alternative energy solutions to meet local needs, particularly as communities and industries shift towards electrification. This insight has been valuable to the IESO and will help to inform future discussions to examine and consider these types of initiatives and the opportunities that they may present in future planning efforts. To that end, ongoing discussions will continue through the IESO's Northwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and planning initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Northwest IRRP engagement webpage.

9.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their own planning and priorities to ensure that these plans were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with targeted municipalities in the region to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; reliability concerns; and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

9.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Northwest Ontario and provide opportunities to provide input, the IESO invited Indigenous communities located in or near the Northwest region to participate in webinars that were held on:

- December 8, 2020
- May 20, 2021
- September 27, 2021
- November 2, 18, 29, 2021
- April 25 and 26, 2022
- November 3, 2022

The First Nation communities that were invited to the webinars were:

- Animakee Wa Zhing No. 37
- Animbiigoo Zaagi'igan Anishinaabek
- Anishinaabeg of Naongashiing (Big Island)
- Anishinabe of Wauzhushk Onigum
- Aroland
- Bearskin Lake
- Big Grassy River (Mishkosiminiziibiing)
- Biinjitiwaabik Zaaging Anishinaabek
- Bingwi Neyaashi Anishinaabek
- Cat Lake
- Constance Lake
- Couchiching
- Deer Lake
- Eabametoong
- Eagle Lake
- Fort William
- Grassy Narrows
- Iskatewizaagegan No. 39
- Kasabonika Lake
- Keewaywin
- Kiashke Zaaging Anishinaabek
- Kingfisher Lake
- Kitchenuhmaykoosib Inninuwug
- Lac des Mille Lacs
- Lac La Croix

- Lac Seul
- Long Lake No. 58
- Marten Falls
- McDowell Lake
- Michipicoten
- Mishkeegogamang
- Mitaanjigamiing
- Muskrat Dam Lake
- Naicatchewenin
- Namaygoosisagagun
- Naotkamegwanning
- Neskantaga
- Netmizaaggamig Nishnaabeg (Pic Mobert)
- Nibinamik
- Nigigoonsiminikaaning
- Niisaachewan Anishinaabe Nation
- North Caribou Lake
- North Spirit Lake
- Northwest Angle No. 33
- Ojibway Nation of Saugeen
- Ojibways of Onigaming
- Pays Plat
- Pikangikum
- Poplar Hill
- Rainy River
- Red Rock Indian Band
- Sachigo Lake
- Sandy Lake
- Seine River
- Shoal Lake No. 40
- Slate Falls
- Wabaseemoong
- Wabauskang
- Wabigoon Lake
- Wapekeka
- Washagamis Bay (Obashkaandagaang)
- Wawakapewin
- Webequie
- Whitesand
- Wunnumin Lake

The Métis communities that were invited to the webinars were:

- MNO Atikokan Métis Council
- MNO Greenstone Métis Council
- MNO Kenora Métis Council
- MNO Northwest Métis Council (Dryden)
- MNO Sunset Country Métis Council (Fort Frances)
- MNO Superior North Shore Métis Council (Terrace Bay)
- MNO Thunder Bay Métis Council
- Red Sky Independent Métis Nation

9.5.1 Information about Indigenous Participation and Engagement in Transmission Development

By conducting regional planning, the IESO determines the most reliable and cost-effective options after it has engaged with stakeholders and Indigenous communities and publishes recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement the recommended solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report.

In instances where transmission is the recommended option, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Aboriginal and treaty rights, with any approval including steps to avoid or mitigate impacts to said rights. MECP oversees the consultation process generally but may delegate the procedural aspects of consultation to the proponent. Following development work, the proponent will then apply to the OEB for approval through a Leave to Construct hearing and, only if approval is granted, can it proceed with the project. In consultation with MECP, project proponents are encouraged to engage with Indigenous communities on ways to enable participation in these projects.

There are no new transmission projects recommended as a result of this Northwest planning initiative.

10. Conclusion

The Northwest IRRP identifies electricity needs in the region over the 20-year period from 2021-2040, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a coordinated approach with bulk system planning where such linkages are identified in the IRRP.

In the near term, the IRRP recommends new and/or upgraded stations to address station capacity needs at Crilly DS and Margach DS, further refinement of non-wires alternatives at Kenora MTS, reconfiguration of Fort Frances TS to improve customer reliability at Fort Frances MTS, and additional reactors at or near Pickle Lake SS to manage high voltages so that E1C can be operated normally open. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

The IRRP recommends that the Working Group monitor growth, particularly in the Red Lake and Fort Frances areas. The IRRP studied high growth sensitivities to establish load meeting capabilities in these areas against which growth should be monitored to determine when future regional planning activities should be triggered. The IESO will update its mining sector demand forecast in early 2023 and provide updates to the Working Group. Electricity demand at White Dog DS and Marathon DS should also be monitored to confirm the timing of station capacity needs emerging in the 2030's. No firm recommendations are required for these potential long-term needs at this time.

The IESO will continue the Supply to the Ring of Fire Study in 2023. The scope and timing will evolve with government policy direction and the IESO will share updates with the Working Group to inform upcoming regional planning activities.

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

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