# Northwest Region Integrated Regional Resource Plan Addendum

North of Dryden Sub-Region
August 2025

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# List of Acronyms

| | |
|---|---|
| APS | Achievable Potential Study |
| ATB | Annual Technology Baseline |
| 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 |
| LMC | Load Meeting Capability |
| LTE | Long-term Emergency |
| NERC | North American Electric Reliability Corporation |
| NOCS | Northern Ontario Connection Study |
| NOMA | Northwestern Ontario Municipal Association |
| 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 |
| SIA | System Impact Assessment |
| TFS | Technical Feasibility Study |
| TS | Transformer Station |
| TWG | Technical Working Group |
| ULTC | Under-Load Tap Changer |

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

This IRRP Addendum Report was prepared on behalf of the Technical Working Group (Working Group) of the North of Dryden sub-region which included the following members:

Independent Electricity System Operator (IESO)

Wataynikaneyap Power

Hydro One Networks Inc. (Hydro One Transmission)

Hydro One Networks Inc. (Hydro One Distribution)

Atikokan Hydro Inc.

Fort Frances Power Corporation

The Working Group assessed the reliability of electricity supply to customers in the North of Dryden sub-region over a 25-year period beginning in 2025; 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 North of Dryden Working Group members agree with the IRRP's Addendum recommendations and support the implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations.

# Executive Summary

The Northwest Integrated Regional Resource Plan (IRRP) Addendum addresses electricity system needs in the North of Dryden sub-region over a 25-year horizon, from 2025 to 2050. While the 2023 Northwest IRRP did not identify firm electricity needs in this sub-region, it acknowledged that new needs could emerge if growth in the mining sector materialized. In 2024, the IESO received further information indicating significant potential load growth tied to mining developments in the region. In response, the IESO initiated this Addendum study ahead of the standard five-year planning cycle to proactively assess system adequacy and ensure reliable electricity supply.

The North of Dryden sub-region includes Dryden, Ear Falls, Red Lake, and Pickle Lake, and encompasses 21 remote First Nation communities connected via the Wataynikaneyap transmission system. Electricity planning for the region is carried out by a Technical Working Group (TWG), which includes the Independent Electricity System Operator (IESO), licensed transmitters, and local distribution companies. In this sub-region, the TWG includes Hydro One Networks Inc. and Wataynikaneyap Power, who together support the development of coordinated solutions to meet emerging electricity needs.

Electricity demand in the region is forecasted to grow significantly, with peak demand increasing from approximately 120 MW in 2023 to over 420 MW under the reference scenario and up to 750 MW under extreme growth by 2050. This growth is primarily driven by mining sector expansion and community growth. The IRRP developed three demand scenarios; Reference, High, and Extreme to test system robustness and inform planning decisions.

The Addendum identifies near-, medium-, and long-term electricity system needs in the sub-region. The primary need in the sub-region is in the Red Lake area, where electricity demand is expected to exceed available supply capacity by 2028 due to thermal constraints on the existing 115 kV transmission corridors (E4D and E2R). These constraints are driven by sustained load growth, particularly from mining developments. In the Pickle Lake area, which is supplied by the 230 kV circuit W54W, the existing infrastructure has sufficient capacity to accommodate forecasted load growth under the reference scenario. However, additional voltage support will be required toward the end of the planning horizon to maintain system reliability and ensure compliance with planning criteria. This includes the installation of reactive compensation to address emerging voltage constraints and support future connections.

To address these needs, the TWG recommends reinforcing the existing 115 kV transmission corridor in the area. This includes two new 230 kV double-circuit transmission lines, one from Dryden TS to Ear Falls TS and the other from Ear Falls TS to Red Lake SS, along with four new 230/115 kV autotransformers and reactive compensation at Red Lake SS, Ear Falls TS, and Pickle Lake TS. The existing 115 kV circuits E4D and E2R will be reconfigured to operate normally open, providing backup supply during outages. This option meets all applicable planning criteria, addresses imminent connection needs in the Red Lake area, and reinforces the transmission system to support long-term growth and enable economic development across the North of Dryden sub-region. This option:

- Supports regional electricity needs through 2050 and beyond, across reference, high, and extreme demand scenarios.
- Enhances reliability and reduces the risk of load interruptions in the North of Dryden sub-region.
- Facilitates the connection of new resources including hydroelectric, biomass, and other generation by lowering connection costs and enabling power transfers to the broader grid.
- Strengthens system resilience and robustness while meeting all applicable planning criteria.
- Offers long-term cost efficiency, as building a double-circuit line upfront is significantly more economical than adding a parallel single-circuit line later.
- Minimizes environmental and land-use impacts by leveraging existing rights-of-way where feasible.

Non-wires alternatives (NWAs) were also evaluated, including natural gas, biomass, solar, wind, and battery energy storage systems. While some options offer system benefits, they face limitations in reliability and/or land use. Natural gas, while cost-competitive, presents challenges related to fuel supply, regulatory compliance, and community acceptance. Hybrid renewable options require extensive land and cannot serve all hourly load requirements. Ultimately, NWAs were deemed unsuitable as standalone solutions for the Red Lake area's long-term needs but may complement transmission investments in future planning cycles.

Extensive engagement was conducted with municipalities, Indigenous communities, industry stakeholders, and the public. Feedback emphasized support for the recommended transmission solution, concerns about transmission lead times, interest in enabling economic development, and the importance of respecting Indigenous land rights and ensuring meaningful participation. These insights were incorporated throughout the planning process.

In conclusion, the IRRP Addendum recommends Transmission Option 3 – Double Circuit as the preferred solution to meet electricity needs in the North of Dryden sub-region. This option supports regional growth and reliability through 2050 and beyond, aligns with planning criteria and stakeholder expectations, and enables future resource development and community expansion. The TWG will continue to monitor demand growth, particularly in Pickle Lake, and initiate further reinforcements as needed. The next cycle of regional planning for Northwest Ontario began in Q3 2025 and will build upon the findings of this Addendum.

# 1. Introduction

This Northwest Integrated Regional Resource Plan (IRRP) Addendum Study ("the Study") builds on the Independent Electricity System Operator's (IESO) 2023 Northwest IRRP, published in January 2023. This addendum study was initiated by the Technical Working Group (TWG) earlier than the mandated five-year cycle of regional planning to address emerging electricity needs in the North of Dryden sub-region, where growing demand is anticipated due to mining developments and community expansion. Its objective is to ensure that the transmission system can continue to reliably support future electricity requirements in this rapidly growing area.

The North of Dryden sub-region encompasses a large geographic area extending north from Dryden through Ear Falls, Red Lake, and Pickle Lake, reaching as far as Sachigo Lake in the northwest and Big Trout Lake in the northeast. It includes the recently completed Wataynikaneyap transmission system, which connects 17 remote First Nation communities. This sub-region spans parts of the Robinson-Superior Treaty area, First Nation Treaty areas 3, 5, and 9, as well as Regions 1 and 2 of the Métis Nation of Ontario (MNO), and includes a total of 21 remote communities.

For planning purposes, the region is defined by its electrical infrastructure rather than geographic boundaries. It is supplied by 230 kV and 115 kV circuits extending east from Kenora and north from Atikokan, and includes the 230/115 kV systems located north of Dryden. A geographic map and single line diagram illustrating the sub-region's infrastructure are provided in Figure 1.1 and Figure 1.2 respectively.

Four local distribution companies (LDCs) serve the area: Hydro One Networks Inc., Atikokan Hydro Inc., and Fort Frances Power Corporation. Transmission assets in the region are owned by two licensed transmitters: Hydro One Networks Inc. and Wataynikaneyap Power. This IRRP Addendum was prepared by the IESO on behalf of a Working Group composed of these LDCs and transmitters.

This Addendum follows from the previous regional planning cycle, where Hydro One published its Needs Assessment in July 2020[1] and the IESO issued the Scoping Assessment Outcome Report in January 2021[2]. The Northwest IRRP was released in January 2023[3] and the Northwest Regional Infrastructure Plan (RIP)[4] was published in August 2023. This Addendum supplements the 2023 Northwest IRRP and does not replace or supersede its findings.

[1] NW 2023 Needs Assessment Report can be found on Hydro One's Northwest Ontario regional planning website.
[2] NW 2023 Scoping Assessment Outcome Report can be found on IESO's Northwest regional planning engagement website.
[3] Northwest (NW) 2023 Integrated Regional Resource Plan can be found on IESO's Northwest regional planning engagement website.
[4] Northwest Regional Infrastructure Plan (RIP) 2023 can be found on Hydro One's Northwest regional planning engagement website.

**Figure 1.1 | Geographic Map of the North of Dryden Sub-Region**

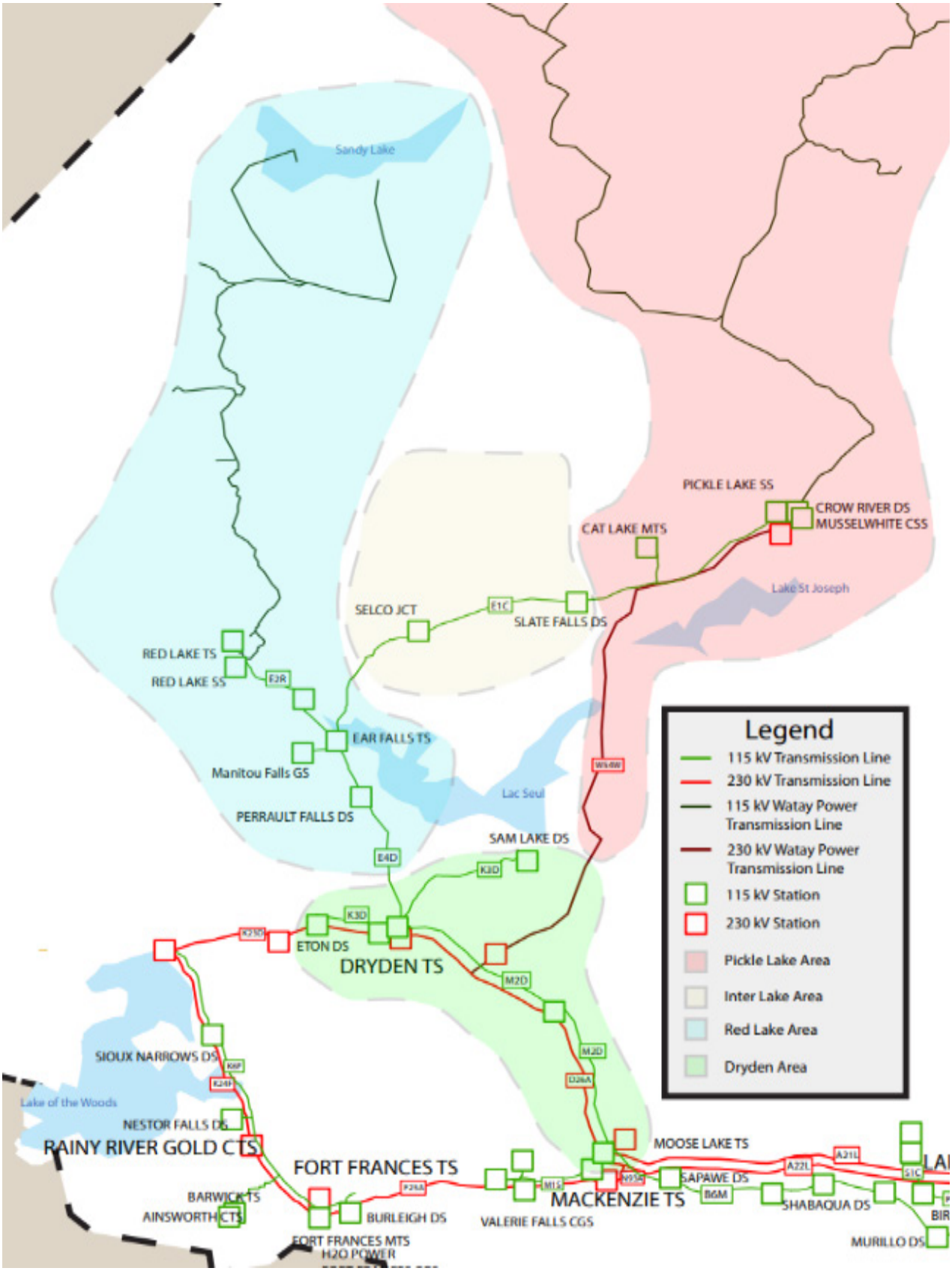
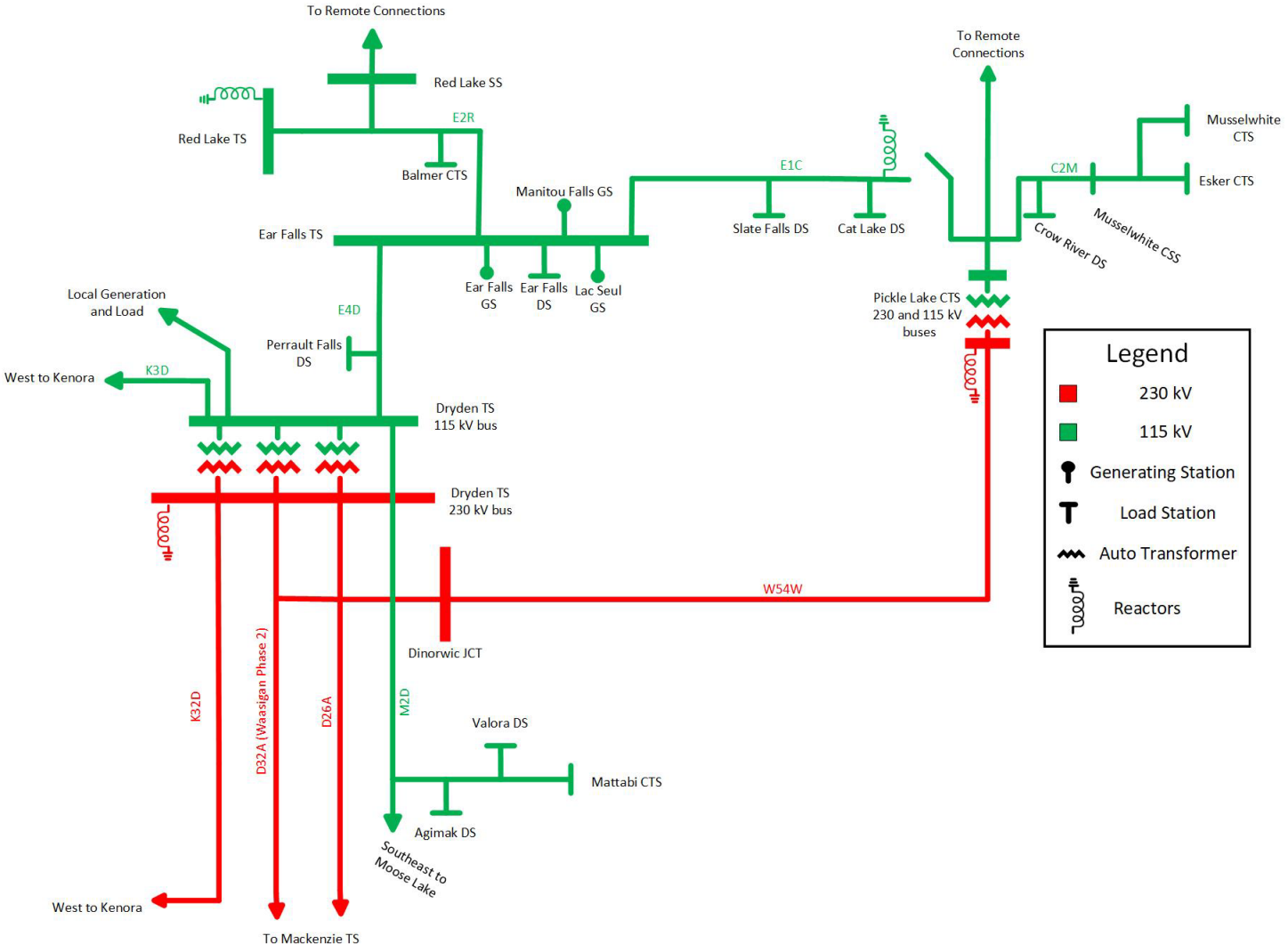


**Figure 1.2 | Current Electricity Infrastructure in the North of Dryden Sub-Region**



# 2. The Integrated Regional Resource Plan Addendum

This IRRP Addendum outlines recommended actions to address the electricity needs of the North of Dryden sub-region over the next 25 years. These recommendations are informed by projected electricity demand growth and assessed against the capabilities of the existing transmission infrastructure. The analysis is guided by the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards established by the North American Electric Reliability Corporation (NERC). Each recommendation has been evaluated based on system reliability, cost-effectiveness, technical feasibility, optimal use of existing infrastructure where practical, and stakeholder input.

Several major transmission reinforcement projects in the Northwest region are foundational to enabling future development in the North of Dryden sub-region:

- **East-West Tie Reinforcement:** A new double-circuit 230 kV transmission line from Wawa TS to Marathon TS and from Marathon TS to Lakehead TS. In service since 2022.
- Waasigan Transmission Line Project:
    - *Phase 1* – A new double-circuit 230 kV line from Lakehead TS to Mackenzie TS (under construction; expected in-service December 2025).
    - *Phase 2* – A new single-circuit 230 kV line from Mackenzie TS to Dryden TS (expected in-service December 2027).
- **Wataynikaneyap Transmission Project:** A new single-circuit 230 kV line from Dinorwic Junction (near Dryden) to Wataynikaneyap TS (near Pickle Lake), along with associated 115 kV circuits connecting remote communities north of Pickle Lake and Red Lake. In service as of 2025.
- **Pickle Lake Shunt Reactor Project:** Installation of a 115 kV line shunt reactor at Pickle Lake SS to moderate voltage and enable a normally open point on circuit E1C. Expected in-service October 2026.

With the East-West Tie and Wataynikaneyap projects already in service, and the Waasigan Transmission Line progressing toward completion, these reinforcements collectively strengthen the 230 kV backbone across the Northwest. These upstream enhancements position the system to accommodate targeted investments within the North of Dryden sub-region, supporting future load growth tied to industrial and community expansion.

Electricity demand in the sub-region is expected to increase significantly, primarily driven by mining and industrial activity. These developments can result in large, step-changes in demand with relatively short lead times, presenting challenges for long-term transmission planning. To address this, the IRRP considered high-growth demand scenarios to test the robustness and adaptability of the plan under more aggressive assumptions.

This plan is organized into two components:

- **Near- and Medium-Term Recommendations:** Actions and studies to be undertaken by Working Group members within specified timeframes. These actions address needs with high forecast certainty and require committed action during this planning cycle.
- **Ongoing Monitoring:** Activities to track long-term or potential needs that may emerge under high-growth scenarios but remain uncertain in the current forecast. These include monitoring electrification trends, energy efficiency performance, and updates to industrial or mining development plans.

This phased approach ensures that immediate system needs are addressed while maintaining flexibility to adapt as new information becomes available.

## 2.1 Near- and Medium-Term Recommendations

This section summarizes the electricity system needs identified in the Study and the recommended actions to address them.

### 2.1.1 Red Lake Area Supply Capacity Need

Electricity demand in the Red Lake area is expected to exceed available supply capacity by 2028, driven by sustained growth. Under the reference forecast, capacity needs are projected to rise from 40 MW in 2028 to 115 MW by 2050. The current system is constrained during summer conditions due to pre-contingency thermal limits on the 115 kV circuits E4D (Dryden to Ear Falls) and E2R (Ear Falls to Red Lake). Load forecasts for the Red Lake Area under reference, high-growth, and extreme-growth scenarios are provided in Figure 6.5. These recommendations are based on the reference forecast.

Transmission reinforcement options were assessed, ranging from targeted upgrades along the Dryden–Ear Falls–Red Lake corridor (estimated capital cost: $800–$1,000 million) to broader incremental reinforcements extending through the Dryden–Pickle Lake–Ear Falls corridor (estimated cost: $2,500 million), which would also enhance supply capacity for the Pickle Lake area. These options and their benefits are discussed further in Section 7.

Several non-wires alternatives (NWAs) were evaluated, including:

- 130 MW natural gas fired generating resource
- 130 MW biomass fired generating resource
- A hybrid resource consisting of 400 MW battery storage, 4,000 MW solar, and 150 MW wind

However, these NWA were found unsuitable as stand-alone solutions due to technical and reliability constraints:

1. The 115 kV network's ~80 MW capacity limits the ability to host large, centralized resources, requiring fragmented siting and connections.
2. The single-circuit configuration of transmission lines introduces unacceptable reliability risks under ORTAC load security criteria, particularly as demand approaches 150 MW by 2040 under the reference scenario which could occur earlier if mining developments materialize sooner.

Therefore, to address the supply capacity needs in the Red Lake area, the IRRP recommends the following transmission investments:

- Hydro One Transmission to:
- Construct two new double-circuit 230 kV transmission lines: one from Dryden TS to Ear Falls TS, and another from Ear Falls TS to Red Lake SS.
- Install two new 250 MVA 230/115 kV autotransformers at Ear Falls TS.
- Reconfigure existing 115 kV circuits E4D and E2R to operate normally open, allowing them to serve as backup supply during outages.
- Wataynikaneyap Power to:
- Install two new 250 MVA 230/115 kV autotransformers at Red Lake SS.

While NWAs are not viable as primary solutions, they may offer supply diversity and resilience. The IRRP therefore recommends that the IESO explore cost-effective supply resources to complement these transmission reinforcements during the next Northwest Ontario IRRP cycle, expected to begin later this year.

### 2.1.2 Pickle Lake Area Supply Capacity Need

The current load meeting capability (LMC) of the Pickle Lake area is approximately 125 MW, constrained by pre-contingency voltage limits as defined by ORTAC. Voltage sensitivity analysis under the reference load growth scenario indicates that these criteria will be violated at Pickle Lake TS by 2043, limiting the area to supply further demand. To address this, capacitive compensation will be required to support future load connections.

However, rather than waiting until 2043, the IRRP recommends advancing the installation of a 40 MVar capacitor bank at Pickle Lake TS. This proactive step will not only mitigate the anticipated voltage deficiencies but also deliver near-term benefits by improving operability during outages and supporting load restoration efforts. The region currently faces reliability challenges due to limited remote operational capability and the absence of backup supply, which increases restoration time and complexity. The capacitor bank will help alleviate these issues by enhancing voltage stability and reactive support under contingency conditions.

Under N-1 conditions, ORTAC load security criteria limit interruptible load to 150 MW. While the reference scenario remains within this threshold, the high-growth scenario exceeds it by 2030. Load forecasts under reference, high-growth, and extreme-growth scenarios are shown in Figure 6-2-2. Recommendations in this section are based on the reference scenario.

Looking ahead, the plan recommends that the TWG continue to monitor demand growth and explore reinforcement options for the corridor between Pickle Lake and Red Lake. This would further improve backup supply capability and overall reliability in the region.

Near- and medium-term recommendations are summarized in Table 2.1 and discussed further in Section 7.

**Table 2.1 | Summary of Near- and Medium-Term Recommendations**

| Need/Subsystem | Recommendation | Lead Responsibility | Implementation |
|---|---|---|---|
| Red Lake Area Supply Capacity | Reinforce the existing 115 kV E2R and E4D transmission corridors. Hydro One Transmission will construct two new double-circuit 230 kV transmission lines: one from Dryden TS to Ear Falls TS, and another from Ear Falls TS to Red Lake SS. Hydro One will install two new 250 MVA 230/115 kV autotransformers at Ear Falls TS, and Wataynikaneyap Power will install two new 250 MVA 230/115 kV autotransformers at Red Lake SS. Upon completion, the existing 115 kV circuits E4D and E2R will operate in a normally open configuration and serve as backup supply during outages. Hydro One and IESO will collaborate to refine location of open points. | Hydro One; Watay Power | Hydro One to determine in-service date reflecting urgency of 2028 need date. |
| Pickle Lake Area Supply Capacity | Install a 40 MVar capacitor at Pickle Lake TS to address voltage concerns. Monitor demand growth and trigger planning to evaluate reinforcing the corridor between Pickle Lake and Red Lake to ensure adequate backup supply and system resilience. | Hydro One; Watay Power | 2030 |

# 3. Development of the Plan

## 3.1 Regional Planning Process

In Ontario, electricity planning at the regional level is carried out through a structured regional planning process. This process assesses the interconnected electricity needs of a region, defined by shared supply infrastructure over the near, medium, and long term, and results in a coordinated plan to ensure reliable and cost-effective electricity supply.

A regional plan considers existing infrastructure, forecast growth, and customer reliability expectations. It evaluates potential solutions and recommends actions to address identified needs.

The current regional planning framework was formalized by the Ontario Energy Board (OEB) in 2013 and operates on a five-year cycle for each of the province's 21 defined planning regions. The process is carried out by the IESO in collaboration with licensed transmitters and local distribution companies (LDCs) within each region. It consists of four key components:

1. **Needs Assessment** – Led by the region's lead transmitter, this initial screening identifies electricity needs and determines whether regional coordination is required.
2. **Scoping Assessment** – Led by the IESO, this step defines the appropriate planning approach and the scope of any recommended planning activities.
3. **Integrated Regional Resource Plan (IRRP)** – Led by the IESO, the IRRP proposes coordinated solutions to meet identified needs.
4. **Regional Infrastructure Plan (RIP)** – Led by the lead transmitter, the RIP provides further detail on recommended wires solutions.

Additional information on the regional planning process and the IESO's planning approach is available in Appendix A of the 2023 Northwest IRRP.

Regional planning is one of several planning activities in Ontario's electricity sector. Bulk system planning, led by the IESO, and distribution system planning, led by LDCs, also play key roles. While each planning level has distinct objectives, there are natural overlaps among them, particularly in areas where infrastructure and customer needs intersect.

## 3.2 The Northwest Region and IRRP Addendum Development

The Northwest IRRP was initiated in January 2021, following Hydro One's Needs Assessment in July 2020 and the IESO's Scoping Assessment Outcome Report in January 2021. In alignment with the standard 18-month IRRP timeline, the original publication was scheduled for July 13, 2022. However, in April 2022, the IESO requested a six-month extension from the OEB to incorporate key developments in the region. This extension allowed for more comprehensive engagement, consideration of additional growth scenarios, and improved coordination with ongoing bulk system studies across both the Northwest and Northeast.

As part of the IRRP, the IESO identified several sub-regions for continued monitoring, including the North of Dryden area. In response to significant load growth and new developments in this sub-region, the IESO initiated an IRRP Addendum in August 2024 to evaluate options for maintaining reliable electricity supply.

# 4. Background and Study Scope

During the first cycle of regional planning, the Northwest region was divided into four sub-regions, each with its own Integrated Regional Resource Plan (IRRP):

- **North of Dryden** (published January 2015)[5]
- **Greenstone-Marathon** (published June 2016)[6]
- **West of Thunder Bay** (published July 2016)[7]
- **Thunder Bay** (published December 2016)[8]

In the second cycle, these sub-regions were considered collectively within the broader context of Northwestern Ontario, culminating in the publication of the 2023 Northwest IRRP. The third cycle of regional planning for the Northwest region commenced in Q3 2025.

## 4.1 Study Scope

This IRRP Addendum addresses emerging electricity needs in the North of Dryden sub-region and evaluates supply options to meet these needs, identifying the most effective solution. The plan was developed by the IESO in collaboration with the Technical Working Group (TWG) and incorporates:

- Forecast electricity demand growth
- Conservation and demand management (CDM)
- Distributed generation (DG)
- Transmission and distribution system capabilities
- Relevant community plans
- Equipment end-of-life considerations
- Developments in the bulk transmission system

[5] North of Dryden IRRP can be found on IESO's North of Dryden regional planning engagement website.
[6] Greenstone-Marathon IRRP can be found on IESO's Greenstone-Marathon regional planning engagement website.
[7] West of Thunder Bay IRRP can be found on IESO's West of Thunder Bay regional planning engagement website.
[8] Thunder Bay IRRP can be found on IESO's Thunder Bay regional planning engagement website.

The IRRP Addendum was guided by the following planning steps:

- Developing a 25-year electricity demand forecast and identifying system needs over that horizon
- Assessing the load meeting capability (LMC) and reliability of the existing transmission system, including facility ratings, transformer performance, local generation, and reactive power devices
- Applying contingency-based assessments and reliability standards from ORTAC, NERC, and NPCC (where applicable)
- Confirming end-of-life asset replacement needs and timing with transmitters and LDCs
- Identifying and evaluating alternatives to address system needs, including generation, transmission, distribution, and non-wires solutions such as CDM
- Conducting sensitivity analyses for areas with high growth potential to test the robustness and flexibility of proposed solutions
- Engaging with communities to understand needs and explore alternatives
- Evaluating options to address near- and long-term needs
- Communicating findings, conclusions, and recommendations in a comprehensive plan

### 4.1.1 Scope of Regional Planning regarding New Connections

Growth in the North of Dryden sub-region is primarily driven by industrial customers, particularly in the mining sector. While many of these customers are not yet connected to the electricity grid but have expressed interest in doing so. This Study also incorporates the latest demand growth forecasts from the municipalities and Indigenous communities and enables future growth. This Study used the best available information to simulate potential future connection configurations.

Rather than evaluating the capability to supply each individual project, the Study focused on assessing the overall adequacy of regional infrastructure to meet projected demand. Local connection requirements for specific projects were only considered where they aligned with broader regional needs[9].

## 4.2 Parallel Planning Activities

Several planning initiatives are underway in parallel with this IRRP Addendum, including the Northern Ontario Bulk Study and the Northern Ontario Connection Study (NOCS). These efforts are expected to inform and complement regional planning activities.

[9] Participation in the IRRP does not replace the formal connection processes required for new customers, including Customer Impact Assessments (CIA) and System Impact Assessments (SIA). Additionally, the absence of identified regional reliability needs in a specific area through the IRRP does not guarantee approval of future connection requests through CIA or SIA processes.

### 4.2.1 Northern Ontario Bulk Study

The IESO initiated the Northern Ontario Bulk Study to address several key objectives:

- Responding to increasing electricity demand in Northern Ontario, driven by mining developments, electrification of metal production, and broader industrial electrification
- Supporting province-wide demand growth, which requires new supply resources and expanded transmission capacity to enable bulk transfers across Ontario
- Advancing the Government of Ontario's Critical Minerals Strategy and Powering Ontario's Growth report by unlocking economic opportunities and enabling resource development in Northern Ontario

The study is evaluating transmission options to reinforce the supply corridor between southern and northern Ontario and exploring new supply resources in the North to meet higher demand growth.

### 4.2.2 Northern Ontario Connection Study

The IESO is conducting the Northern Ontario Connection Study in response to a request from the Government of Ontario to develop supply options in Northwest Ontario that will:

- Connect remote First Nations communities currently reliant on diesel generation
- Improve reliability for grid-connected First Nations communities
- Support critical minerals mining development
- Enable new hydro and renewable resource development

Further engagement for NOCS is planned for late spring/summer 2025, with the study expected to conclude in Q3 2025.

# 5. Electricity Demand Forecast

This section outlines the development of the demand forecast for the North of Dryden sub-region. While IRRPs typically use a 20-year planning horizon, a 25-year forecast was developed for this Addendum to capture the full impact of anticipated mining activity in the area.

The forecast consists of three components: distribution-connected demand, transmission-connected demand, and a focused mining sector forecast. The mining sector forecast is integrated within the transmission-connected category but also presented separately to highlight future incremental demand.

- **Distribution-connected**: The distribution-connected forecast reflects demand served on the distribution systems in the North of Dryden sub-region and is based on information submitted by local distribution companies (LDC). The regional planning process relies on LDCs to consider municipal and regional official plans and First Nations development plans and translate them 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.
- **Transmission-connected**: The transmission-connected forecast reflects demand served directly from the transmission system. This typically consists 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 with individual project proponents, municipal energy committees, and task forces (i.e., Northwestern Ontario Municipal Association [NOMA]). 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

All forecasts in this section refer to non-coincident peak demand, meaning the sum of each station's individual peak demand. Each component is described in further detail below.

## 5.1 Historical Demand

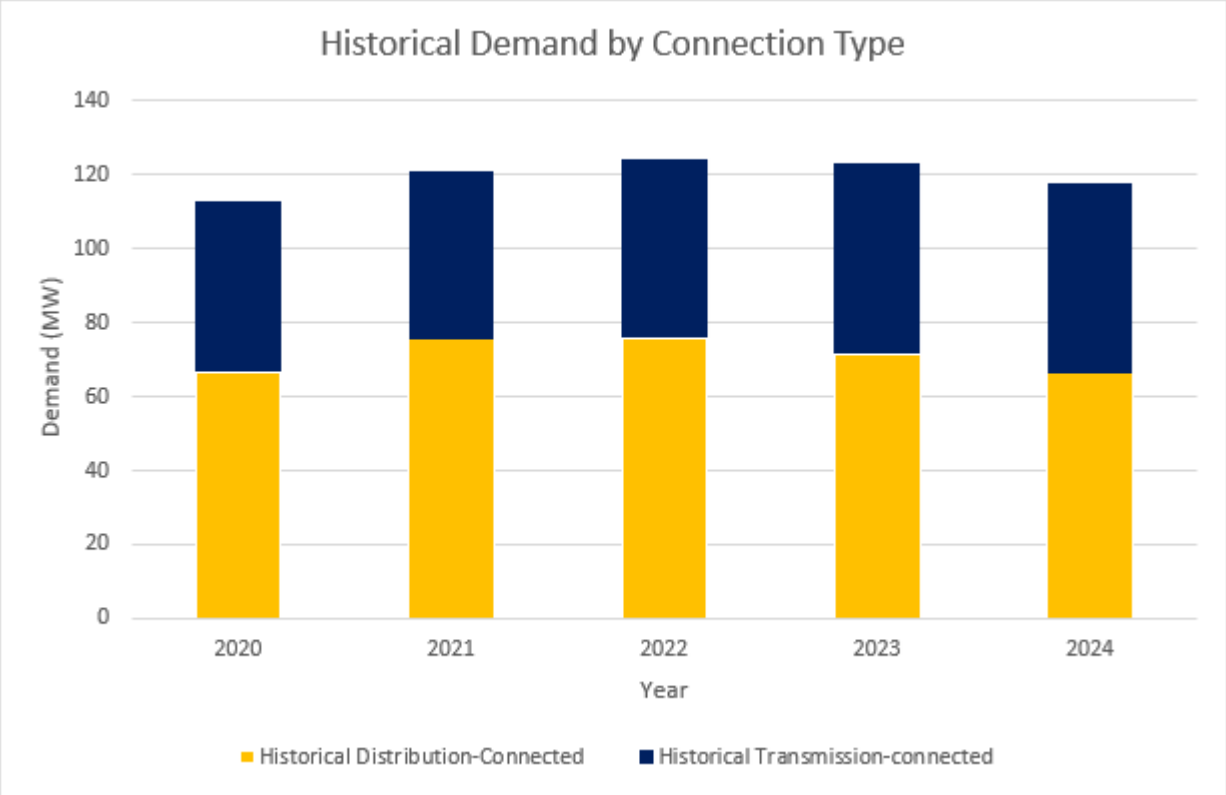
Figure 5.1 illustrates net and gross historical demand over the past five years in the North of Dryden sub-region. Historically, distribution-connected customers have accounted for approximately 60% of peak demand, with the remainder served through transmission connections.

Demand growth was steady through 2022, tapering slightly into 2024, with an average annual growth rate of 0.9%. Peak demand in the sub-region has hovered just above 120 MW from 2021 to 2023.

The North of Dryden sub-region is winter peaking, with annual peak demand typically occurring on winter evenings between 7:00 p.m. and 8:00 p.m.

Distributed generation has historically contributed about 10–15 MW during peak conditions. This contribution was added to the net demand forecast to derive the gross demand forecast. The 2020 gross demand was used as the starting point for the forecast, with station-level adjustments made where anomalous conditions were identified.

**Figure 5.1 | 2020–2024 Historical Demand**




## 5.2 Distribution-connected Forecast

To develop the distribution-connected forecast, each LDC prepared a gross station-level demand forecast for its service territory (see Section 5.2.1). These forecasts were then adjusted to reflect:

- The impact of provincial conservation targets
- Distributed generation contracted through programs such as FIT and microFIT.[10]

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

- Extreme weather conditions

The result is a reference scenario forecast that accounts for expected peak demand under typical operating conditions.

### 5.2.1 Gross Local Distribution Company Forecast

Each participating LDC developed gross demand forecasts at the station level, or at the station bus level for multi-bus stations, based on their understanding of local development plans and customer engagement. These forecasts incorporate anticipated changes in consumer demand due to efficiency improvements and rising electricity prices (i.e., "natural conservation"), but exclude impacts from future distributed generation or new conservation measures, which are accounted for separately by the IESO.

From these forecasts, demand growth from new developments and known connection applications was identified. The compiled distribution-connected forecasts were then adjusted for extreme weather conditions, as shown in Figure 5.2. This gross forecast includes residential loads and distribution-connected mining loads under the reference scenario.

**Figure 5.2 | Total Gross Median and Extreme Weather Distribution-connected Forecast**

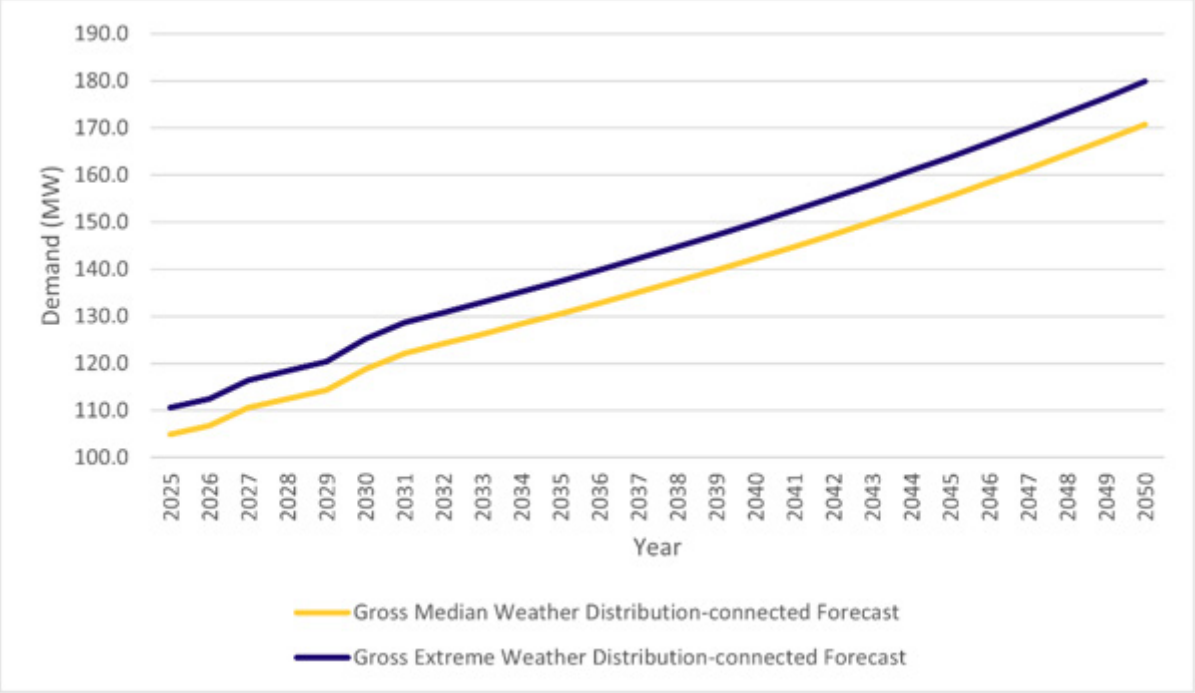
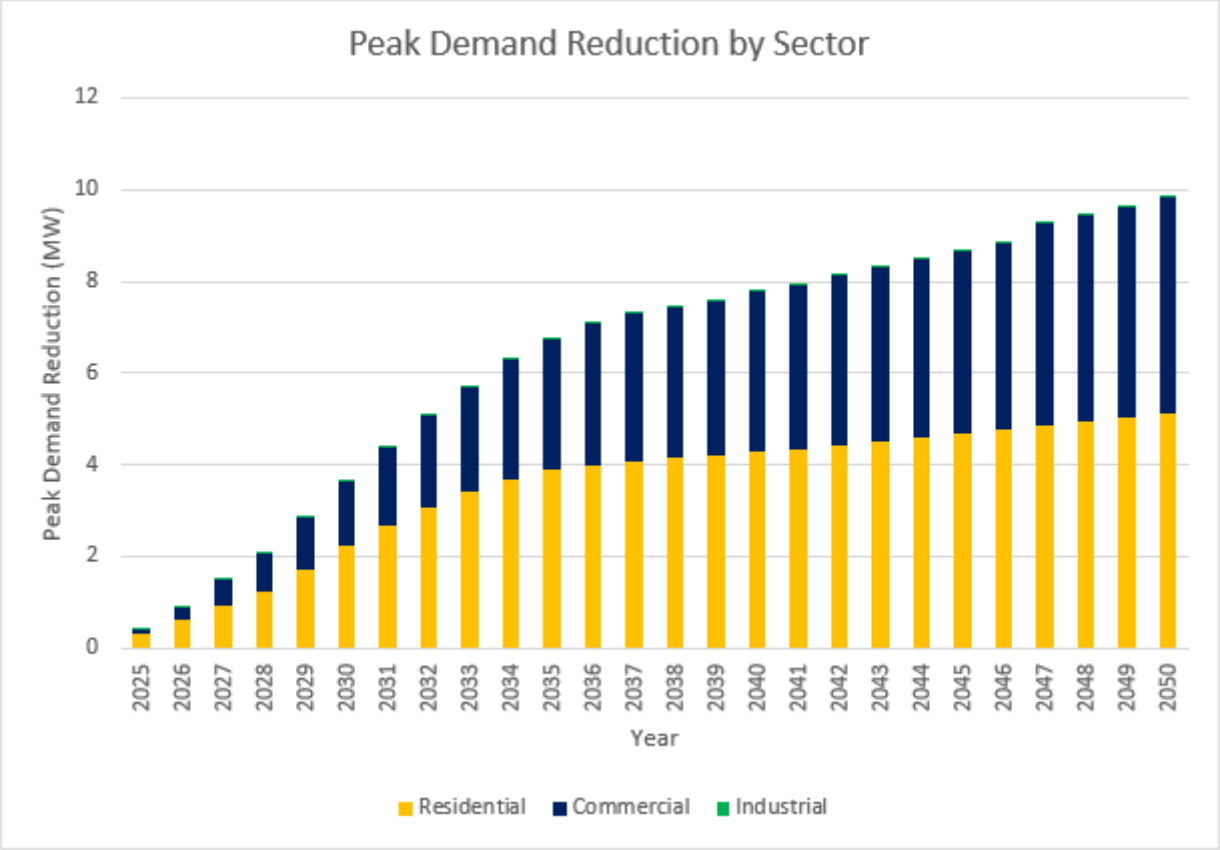


**Figure 5.3 | Contribution of Conservation to Forecast**




### 5.2.2 Contribution of Conservation to the Forecast

Electricity Demand-Side Management (eDSM), previously known as Conservation and Demand Management (CDM), is a clean and cost-effective resource that helps meet the province's electricity needs. The 2025–2036 Electricity Demand-Side Management (eDSM) Framework, which expands on the foundation laid by the 2021–2024 Conservation and Demand Management (CDM) Framework, is a large initiative led by the IESO that aims to reduce electricity demand and improve system efficiency. Electricity Demand-Side Management is achieved through the delivery of programs and collaboration with local distribution companies and partners which contributes to electricity savings in Ontario. This framework enables the IESO to optimize the full value of demand-side management in a variety of ways allowing consumers on a province-wide basis to save on energy costs in their homes, businesses, institutions, and industrial facilities and add more flexibility to regional tailoring and innovation to respond to evolving grid needs.

Figure 5.3 shows the total contribution of conservation to the forecast and is divided into three sectors such as residential, commercial, and industrial.

## 5.3 Transmission-connected Forecast

The North of Dryden sub-region includes several customer transformer stations (CTS) that directly serve large industrial customers connected to the high-voltage transmission system, such as mining operations. Expansion of existing mines and the development of new projects are expected to be the primary drivers of electricity demand growth in the sub-region.

To support planning, the IESO developed a mining sector forecast that incorporates multiple potential future mining projects at various stages of development. This forecast is based on information gathered from project proponents, industry publications, stakeholders, utilities, and government sources. Unlike the distribution-connected forecast, the mining forecast was not adjusted for extreme weather, as industrial demand in this sub-region is generally not sensitive to weather.

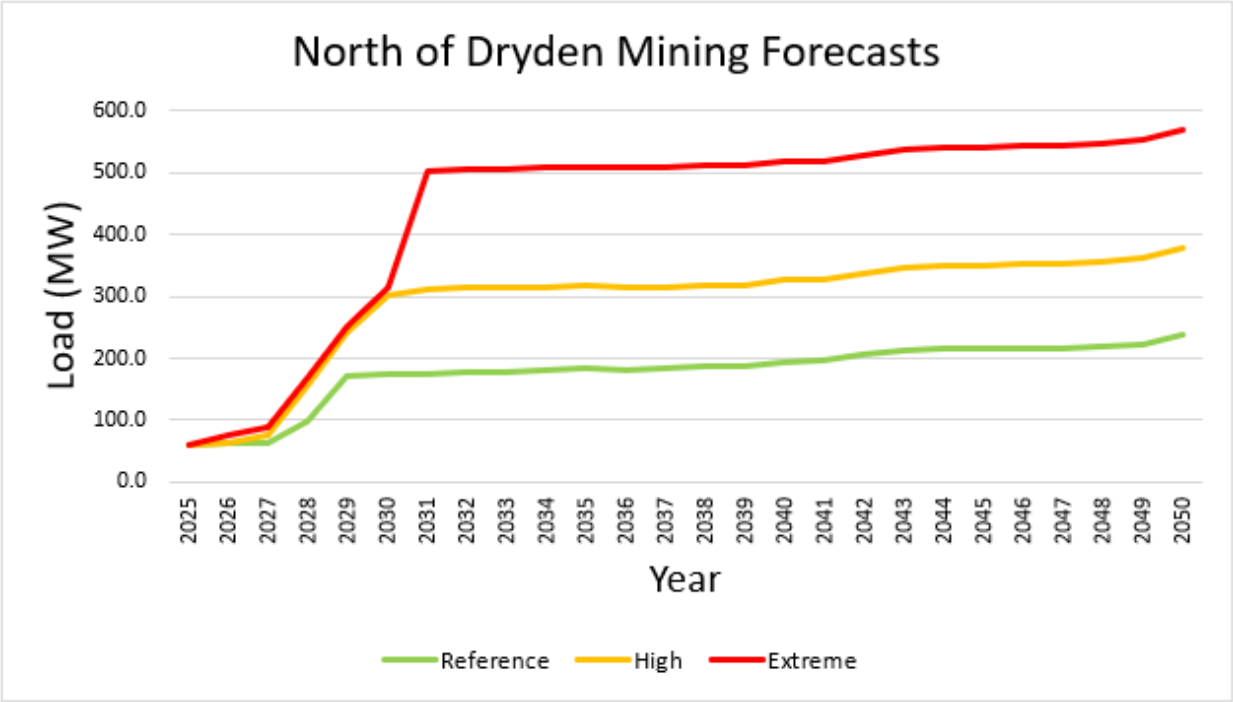
The mining forecast is presented across three scenarios, Reference, High, and Extreme to reflect varying levels of project certainty. The likelihood of a project materializing is informed by factors such as data reliability, project development stage, and expected in-service dates. The IESO also consulted with the Ministry of Energy and Mines and incorporated feedback from the Northwestern Ontario Municipal Association, which recommended removing likelihood-based discounting to better reflect worst-case planning scenarios. NOMA's mining forecast was also used to update the IESO's internal projections.

**Table 5.1 | Mining Forecast Scenario Descriptions**

| Scenario | Description |
|---|---|
| Reference | • Includes all active mining projects, as well as those classified as committe and are most likely to connect<br>• Established from mining forecasts and other commitment indicators/factc such as commodity outlook and prospective in-service dates of projects reported from System Impact Assessments (SIA) and Technical Feasibilit Studies (TFS)<br>• Aligned with 2025 Annual Planning Outlook Reference scenario |
| High | Reference Scenario plus:<br>• Mining projects that have more uncertainty in timing. |
| Extreme | High Scenario plus:<br>• Mining projects that have the greatest uncertainty in timing. |

Figure 5.4 illustrates the mining demand forecast under all three scenarios. The high and extreme cases show significantly higher MW values compared to the reference scenario. The figure includes demand from both new and existing mines but does not include distribution-connected demand.

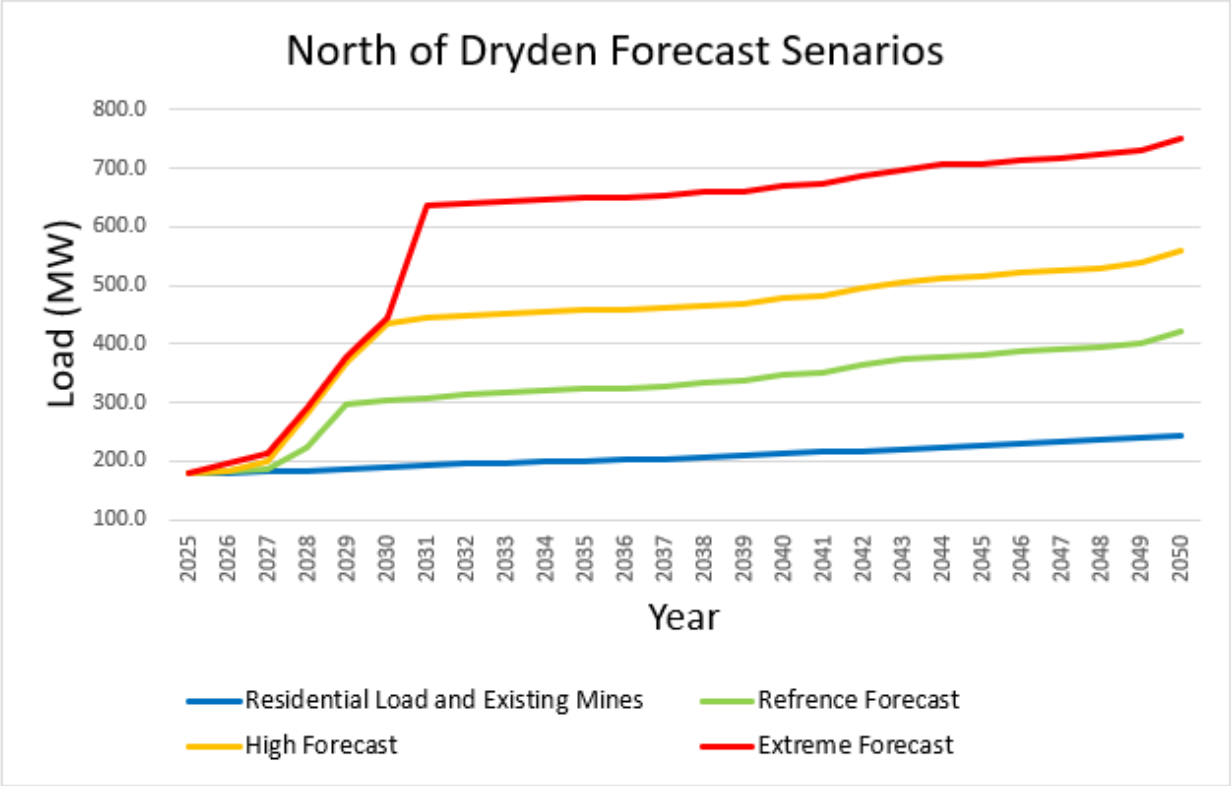
**Figure 5.4 | Mining Demand Forecast**



## 5.4 Total North of Dryden Demand Forecast Scenarios

Figure 5.5 presents the total non-coincident demand forecast for the North of Dryden sub-region. The forecast shows a marked increase in demand beginning in 2027, driven primarily by industrial and mining sector growth.

**Figure 5.5 | Total North of Dryden Demand Forecast**




## 5.5 Demand Profile – Red Lake, Pickle Lake, and Dryden

In addition to annual peak forecasts, hourly demand profiles were developed for the Red Lake, Pickle Lake, and Dryden areas, regions where non-wires alternatives (NWAs) were evaluated. These profiles span 8,760 hours per year and are used over the 25-year forecast horizon to characterize demand at one or more stations with identified needs.

Hourly profiles are developed using a multiple linear regression model based on historical data. The model is applied under various weather and calendar conditions to simulate a range of future hourly demand scenarios. These profiles are then ranked by median energy values, and the median profile is scaled to match the annual peak forecast for each year. This approach supports the evaluation of NWAs by estimating energy requirements and informing technology selection.

It is important to note that these profiles are not intended to deterministically define hourly energy needs for NWAs. Instead, they provide a reasonable approximation of energy requirements for planning purposes, including estimating operating costs and selecting appropriate technologies. As consumer behaviour evolves, new businesses emerge, and electrification trends accelerate, demand patterns may shift significantly. The Technical Working Group will continue to monitor these developments as part of the ongoing planning process.

Details on the demand profiling methodology can be found in Appendix D.1 of the 2023 NW IRRP.

# 6. Needs

This section outlines the transmission system needs identified for the North of Dryden sub-region. These needs focus on localized supply and reliability concerns in key areas, including Dryden, Red Lake, and Pickle Lake. While the IRRP is primarily concerned with regional infrastructure and reliability, it also considers committed transmission projects identified through bulk system planning such as the Waasigan Transmission Line Project where relevant. Although bulk system needs are outside the scope of the IRRP, this report highlights potential interactions between regional and bulk system developments.

This section is organized as follows:

- **Section 6.1** – Methodology for identifying system needs
- **Section 6.2** – Firm station capacity and local operational needs under the reference forecast
- **Section 6.3** – Potential needs under higher-than-forecast growth scenarios.

## 6.1 Needs Assessment Methodology

Based on the reference demand forecast (net demand under extreme weather conditions), system capability, transmitter-identified end-of-life asset replacement plans, and the application of ORTAC and NERC/NPCC standards, the Working Group identified electricity system needs in the following categories:

- **Station Capacity Needs**
  These arise when forecast demand exceeds the ability of regional step-down transformer stations to deliver power to the local distribution network during peak periods. A station's capacity rating is typically based on the 10-day Limited Time Rating (LTR) of its smallest transformer, assuming the largest transformer is out of service. Capacity may also be constrained by downstream or upstream equipment (e.g., breakers, disconnect switches, low-voltage bus, or transmission circuits) that are undersized relative to the transformer rating.
- **Supply Capacity Needs**
  These refer to the transmission system's ability to continuously supply electricity to a local area at peak demand. Supply capacity is determined by the Load Meeting Capability (LMC), which accounts for transmission element limitations under contingency conditions, as defined by ORTAC and NERC/NPCC standards. LMC studies are conducted using power system simulation tools.
- **End-of-life Asset Refurbishment Needs**
  These are identified by transmitters based on asset age, expected service life, condition, and risk of failure. Near-term and early mid-term replacement needs are typically condition-based, while medium- to long-term needs are often based on expected service life.

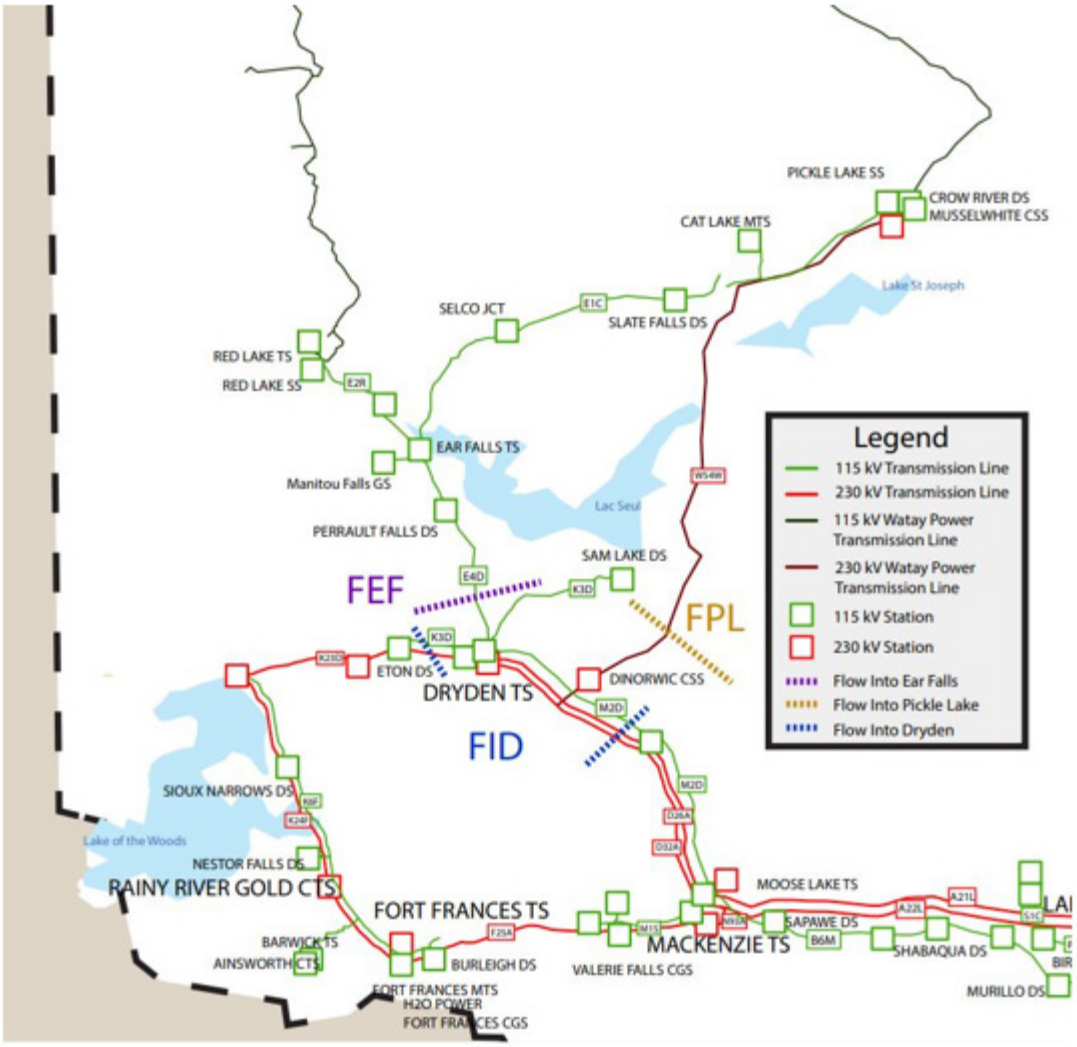
- **Load Security and Restoration Needs**
  These describe the system's ability to minimize the impact of major transmission outages and restore service within reasonable timeframes. Load security refers to the amount of supply interrupted during an outage (e.g., loss of both circuits on a double-circuit tower line), while load restoration refers to the system's ability to recover supply. Requirements are defined in Section 7 of ORTAC.

## 6.2 Needs Identified

To assess transmission reliability and identify emerging needs in the North of Dryden sub-region, the Study analyzed power flows across key interfaces that define how electricity is delivered into major areas. Specifically, the analysis focused on flows into the Ear Falls, Pickle Lake, and Dryden areas, each representing distinct supply paths. These interfaces form the basis for evaluating system capacity and determining when reinforcements may be required.

The geographic extent of each interface is illustrated in Figure 6.1.

**Figure 6.1 | North of Dryden Interfaces**



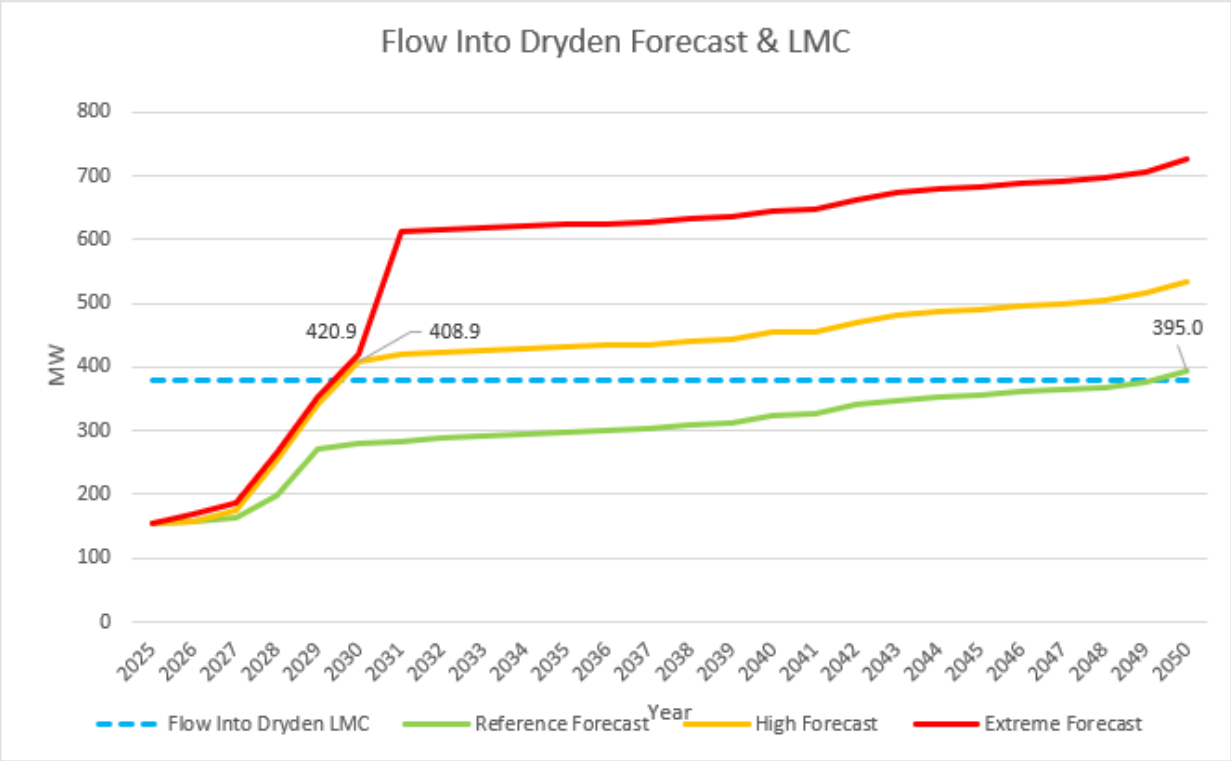

### 6.2.1 Flow into Dryden

The Flow into Dryden (FID) interface is defined by the transfer of electricity into the Dryden area via:

- 230 kV circuits D26A and D32A from Mackenzie (once Waasigan Phase 2 is in service)
- Circuits K23D and M2D from Kenora and Moose Lake

The LMC of this interface is 380 MW, limited by summer thermal constraints under single-element outage conditions. In the event of a contingency on D32A, the remaining D26A circuit reaches its thermal limit when demand north of Dryden exceeds 380 MW. Figure 6.2 shows forecast demand across the FID interface relative to its LMC. Under the Reference scenario, demand remains within limits until approximately 2049, after which exceedances begin to appear. However, under high and extreme growth scenarios, constraints could emerge earlier, highlighting the need for continued evaluation. Further analysis will be conducted in the next regional planning cycle for Northwestern Ontario, commencing in 2025.

**Figure 6.2 | Flow into Dryden Load Meeting Capability and Forecast Scenarios**




### 6.2.2 Flow into Pickle Lake

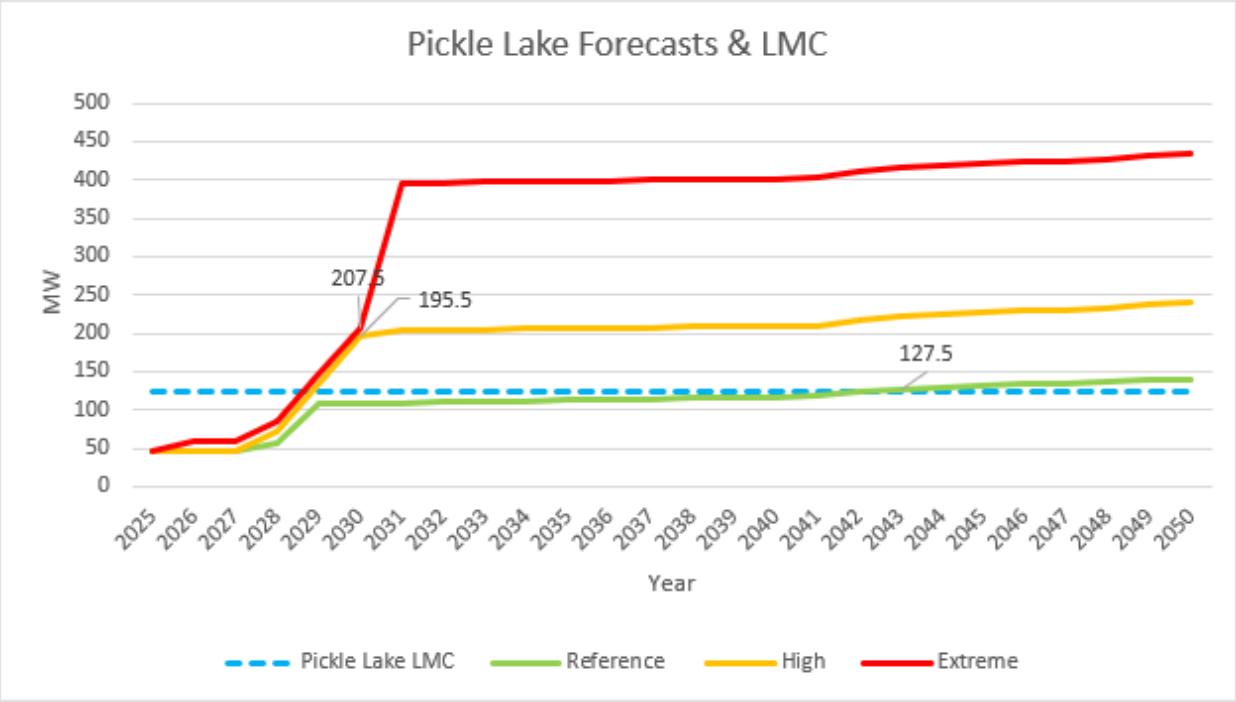
The Flow into Pickle Lake (FPL) interface is defined by the radial supply via circuit W45W, with circuit E1C providing a partial backup path through the Red Lake system. The current load meeting capability (LMC) of the Pickle Lake area is approximately 125 MW, constrained by pre-contingency voltage limits as defined by ORTAC. Voltage sensitivity analysis under the reference load growth scenario indicates that these criteria will be violated at Pickle Lake TS by 2043, limiting the area to supply further demand.

To address this, 40 MVar of capacitive compensation will be required to support future load connections. However, rather than waiting until 2043, the IRRP recommends advancing the installation of a 40 MVar capacitor bank at Pickle Lake TS. This proactive step will not only mitigate the anticipated voltage deficiencies but also deliver near-term benefits by improving operability during outages and supporting load restoration efforts. The region currently faces reliability challenges due to limited remote operational capability and the absence of backup supply, which increases restoration time and complexity. The capacitor bank will help alleviate these issues by enhancing voltage stability and reactive support under contingency conditions.

The capacitor bank addresses the voltage violations in the Pickle Lake area and enables the system to support load levels exceeding 300 MW. However, under N-1 conditions, ORTAC load security criteria limit interruptible load to 150 MW. While the reference scenario remains within this threshold, the high-growth scenario exceeds it by 2030. Load forecasts under reference, high-growth, and extreme-growth scenarios are shown in Figure 6.3. Recommendations in this section are based on the reference scenario.

Looking ahead, the plan recommends that the TWG continue to monitor demand growth and explore reinforcement options for the corridor between Pickle Lake and Red Lake. This would further improve backup supply capability and overall reliability in the region.

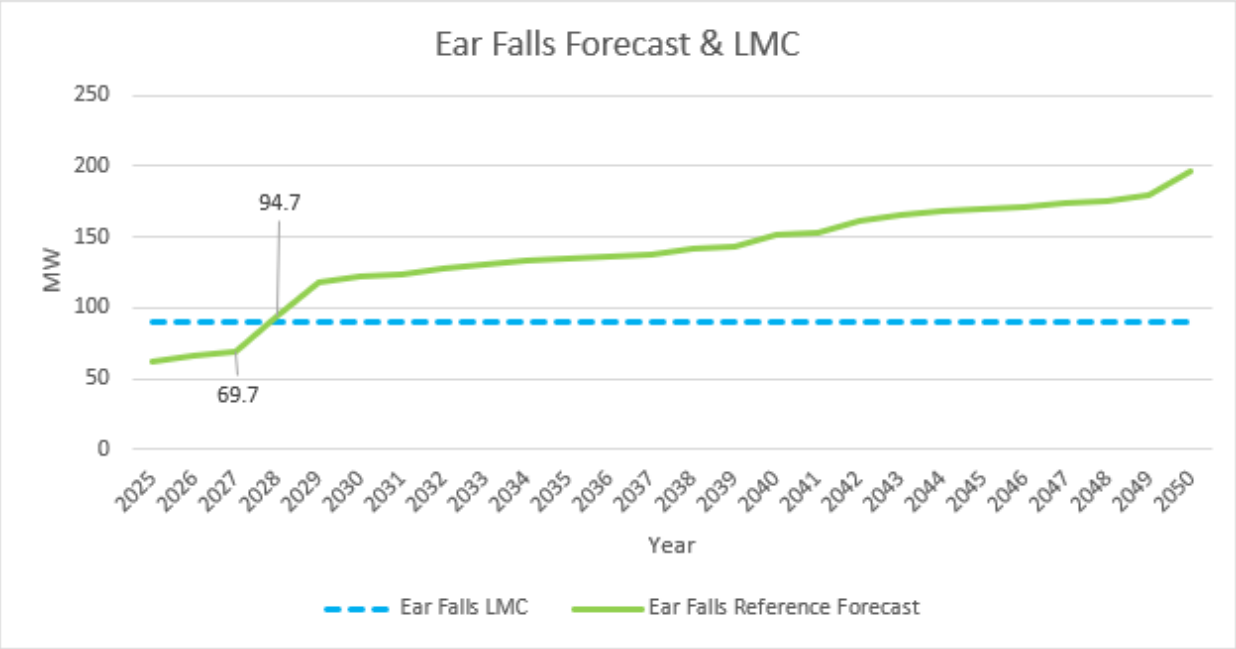
**Figure 6.3 | Flow into Pickle Lake Load Meeting Capability and Forecast Scenarios**



### 6.2.3 Flow into Ear Falls

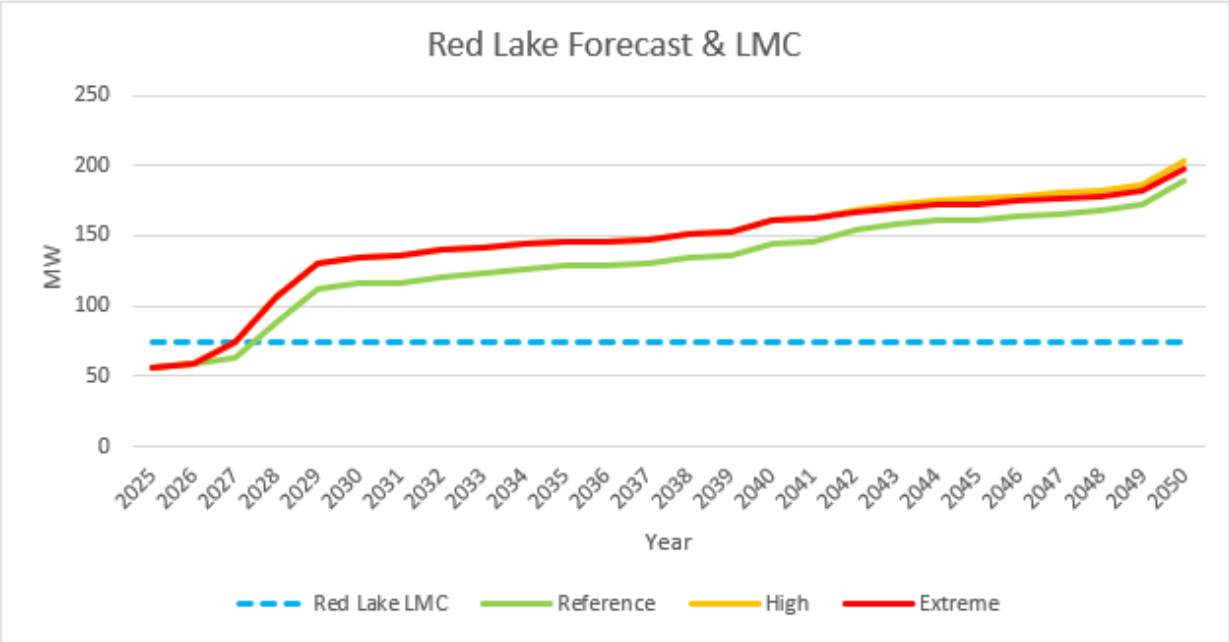
The Flow into Ear Falls (FEF) interface is defined by radial supply via circuit E4D, with circuit E1C offering potential backup. The current LMC for this interface is 90 MW, limited by the summer thermal rating of E4D. Figure 6.4 shows forecasted demand across the FEF interface relative to this threshold. Under the reference forecast, demand exceeds the LMC by 2028.

**Figure 6.4 | Flow into Ear Falls Load Meeting Capability and Forecast Scenarios**




Within the broader Ear Falls area, the Red Lake subsystem is of particular interest. It is radially supplied via circuit E2R, with a summer LMC of 74 MW based on E2R's continuous thermal rating. Figure 6.5 shows forecasted demand across E2R relative to its thermal capacity. The subsystem is nearing its capacity, with thermal limitations on both E2R and E4D constraining supply under pre-contingency summer conditions.

**Figure 6.5 | Red Lake Load Meeting Capability and Forecast Scenarios**




In winter, the LMC increases to approximately 93 MW, though it remains limited by both thermal and voltage constraints on E2R. According to System Impact Assessment (SIA) 2022–730, the connection of the 13 MW Great Bear Resources Mine would require additional reactive compensation and would nearly exhaust the available capacity of the Ear Falls–Red Lake corridor. Any further load additions in the Red Lake area would exceed the current system capability and require transmission reinforcements.

System operators have also raised concerns about the lack of operational flexibility between the Pickle Lake and Red Lake subsystems, particularly given rising demand and the diminishing effectiveness of the Patricia Islanding scheme. Hydro One is currently addressing this issue.

Given that the reference forecast exceeds the FEF and Red Lake LMCs by 2028, reinforcement is required not only at the Ear Falls interface but also within the Red Lake supply corridor. While the high and extreme scenarios do not present immediate thermal constraints, they will require additional reactive support to maintain voltage performance under higher loading conditions.

### 6.2.4 E1C Operation and End-of-Life

The most recent cycle of regional planning identified operational challenges associated with the 115 kV E1C transmission line, which plays a critical role in supporting the Pickle Lake and Interlake area system. Its operational configuration has a significant impact on overall system performance. Two key issues were noted: limited supply capacity when E1C operates in a normally closed state, and high voltage levels under light load conditions when operated in a normally open state.

To maintain system adequacy and meet forecasted demand in the Ear Falls, Red Lake, and Pickle Lake areas, it is necessary to introduce a normally open point at the Ear Falls TS end of E1C. This adjustment would relieve loading on E4D and shift demand in the Pickle Lake area to the newly commissioned 230 kV W54W transmission line. However, operating E1C in an open configuration introduces high voltage concerns during periods of low demand.

As outlined in the 2023 Northwest Regional Infrastructure Plan, the Technical Working Group (TWG) recommended opening E1C at the Ear Falls TS end and installing reactors at Pickle Lake SS to mitigate voltage issues.

Currently, E1C has approximately 30 MW of available supply capacity. However, with potential mining developments in the Interlakes area, this remaining capacity may be insufficient under higher growth scenarios. Additionally, Hydro One has identified E1C as reaching end-of-life, with approximately 70% of pole replacements already completed.

Table 6.1 summarizes the firm transmission needs identified in this Addendum.

**Table 6.1 | Summary of Near-Term and Medium- Term Needs**

| Subsystem | Need | Timing |
|---|---|---|
| Red Lake | The Flow into Red Lake LMC is expected to reach capacity in 2028. Voltage deficiencies due to load growth are also expected to occur by 2028. Reliability in this area is low due to inadequate remote load restoration and backup supply. | 2028 |
| Pickle Lake | Voltage deficiencies due to load growth are expected to occur by 2043. Reliability in this area is low due to inadequate remote load restoration and backup supply | 2043 |
| Ear Falls | E1C is reaching end-of-life and the Hydro One sustainment program is underway to replace the conductor like-for-like | Ongoing |

## 6.3 Long-Term Needs under High Growth Scenario

Electricity demand in the North of Dryden sub-region is primarily driven by the mining sector, which tends to introduce large, incremental blocks of load with short lead times. This can create constraints on the existing transmission system.

To ensure flexibility, high-growth scenarios were studied for the Dryden, Red Lake, and Pickle Lake areas. The goal was to test the robustness and scalability of the transmission solutions developed for the reference scenario. This was achieved by simulating new projects at proposed connection points or nearby transformer stations and applying planning criteria outlined in Section 2.

By quantifying system limitations under high-growth conditions, planners can more effectively monitor demand and initiate timely reinforcements if required. Sensitivity studies show that extensive transmission reinforcement and/or resource procurement will be needed to support forecasted load growth in each area.

**Table 6.2 | Summary of Long-Term Needs**

| Subsystem | Need | Timing |
|---|---|---|
| Dryden | The Flow in Dryden LMC is expected to reach capacity in 2049. This need advances significantly under high and extreme growth scenarios and will trigger additional supply capacity needs on the FID interface and additional reactive compensation. | 2049 |
| Pickle Lake | The Flow in Pickle Lake LMC is expected to reach capacity in 2042. This need advances significantly under high and extreme growth scenarios and will trigger additional supply capacity needs on the FPL interface and additional reactive compensation. | 2042 |

# 7. Options Analysis and Recommendations

This section summarizes the transmission and non-wires options evaluated to address electricity system needs in the North of Dryden sub-region. The analysis includes:

- Section 7.1 – Transmission and non-wires options considered for near- to medium-term needs
- Section 7.2 – Comparison of transmission options
- Section 7.3 – Non-wires alternatives analysis.
- Section 7.4 – Recommendation

## 7.1 Transmission Options

To address the identified electricity needs, three primary transmission options were evaluated, along with a fourth variation involving double-circuiting. These options were informed by Hydro One's technical assessments, IESO planning studies, and feedback from local communities.

### 7.1.1 Option 1

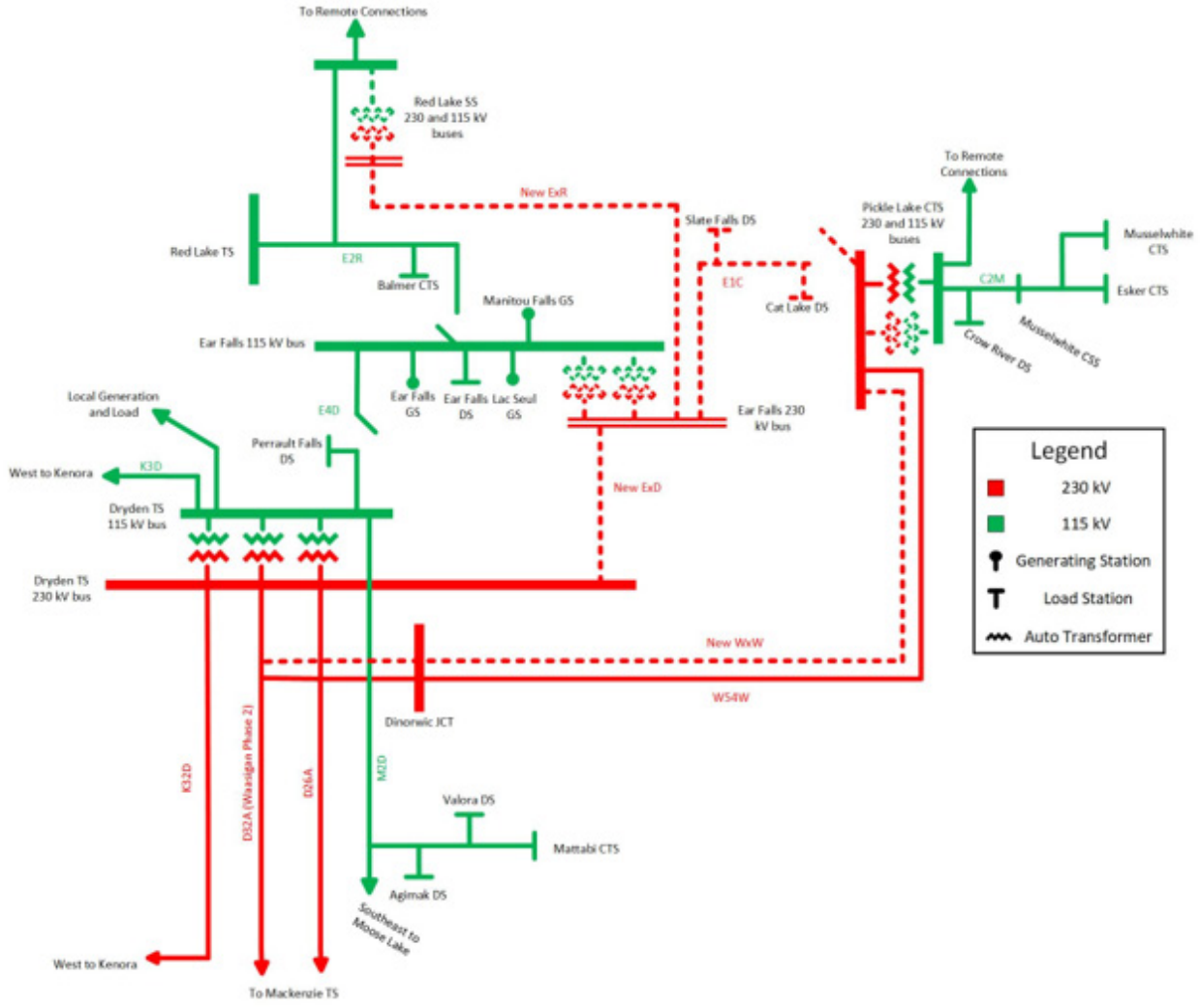
This option includes:

- A new 230 kV transmission line from Dryden to Ear Falls (100 km)
- A new 230 kV transmission line from Ear Falls to Red Lake (62 km)
- A new 230 kV transmission line from Ear Falls to Pickle Lake (260 km)
- A new 230 kV transmission line from Dinorwic Junction to Pickle Lake (302 km)

Supporting infrastructure includes:

- Two 230/115 kV autotransformers at Ear Falls TS
- One 230/115 kV autotransformer at Red Lake SS
- One 230/115 kV autotransformer at Pickle Lake CTS
- Replacement of step-down transformers at Perrault Falls, Slate Falls, and Cat Lake MTS with 230/12.5 or 25 kV units
- A new switching station with a 230 kV ring bus at Dinorwic TS
- Decommissioning of existing 115 kV E1C
- Reactive compensation for voltage support

**Figure 7.1 | Transmission Option 1**




### 7.1.2 Option 2

This option includes:

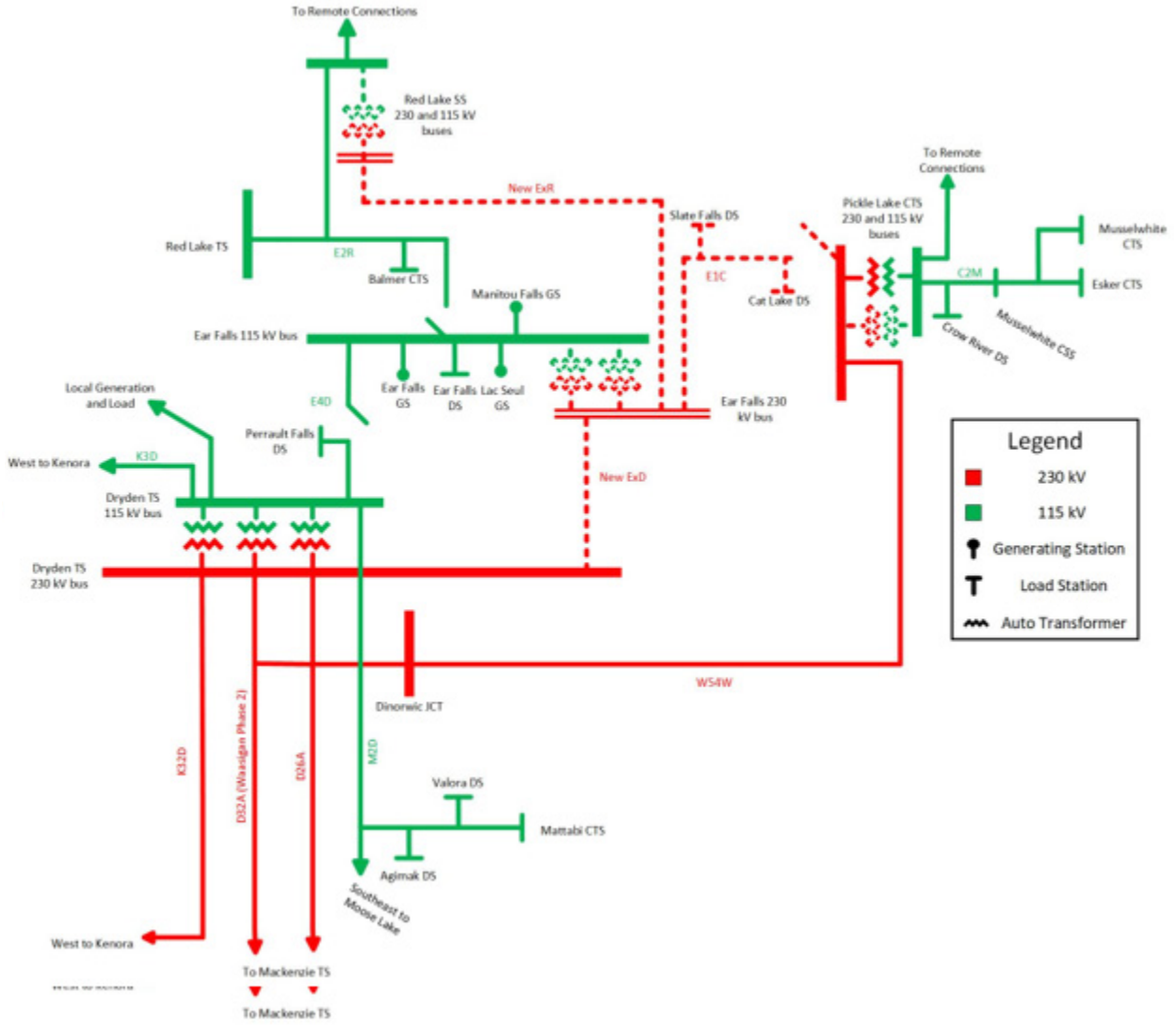
- A new 230 kV transmission line from Dryden to Ear Falls (100 km)
- A new 230 kV transmission line from Ear Falls to Red Lake parallel to E2R (62 km)
- A new 230 kV transmission line from Ear Falls to Pickle Lake (260 km)

Supporting infrastructure includes:

- Two 230/115 kV autotransformers at Ear Falls TS
- One 230/11 kV autotransformer at Red Lake SS
- One 230/115 kV autotransformer at Pickle Lake CTS

- Replacement of step-down transformers at Perrault Falls, Slate Falls, and Cat Lake MTS with 230/12.5 or 25 kV units
- Decommissioning of existing 115 kV E1C
- Reactive compensation for voltage support

**Figure 7.2 | Transmission Option 2**




### 7.1.3 Option 3

This option includes:

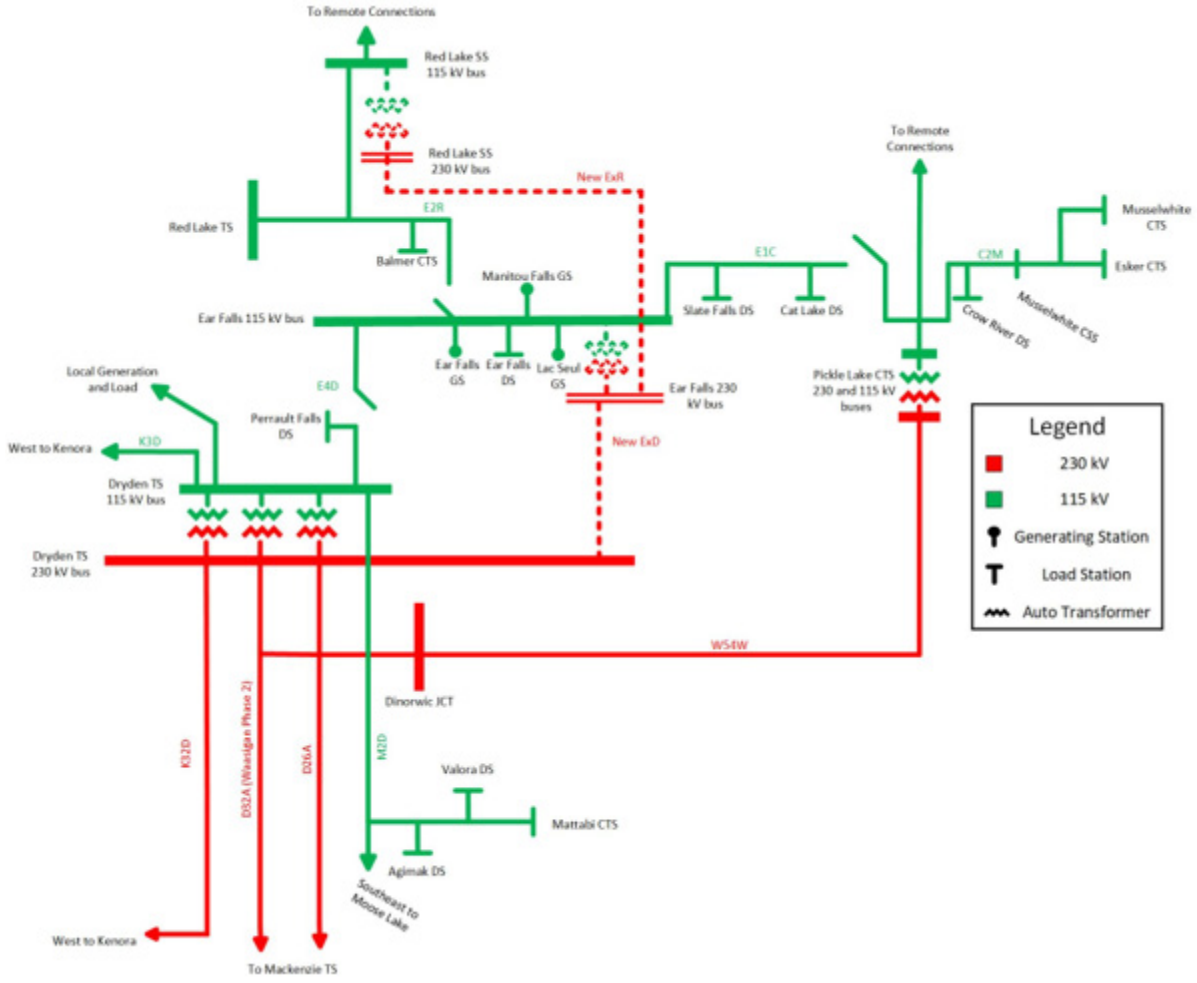
- A new 230 kV transmission line from Dryden to Ear Falls (100 km long)
- A new 230 kV transmission line from Ear Falls to Red Lake (62 km long)

Supporting infrastructure includes:

- One 230/115 kV auto-transformer at Ear Falls TS
- One 230/115 kV auto-transformer at Red Lake SS.
- Reconfiguration of existing 115 kV circuits E4D and E2R to operate normally open
- Reactive compensation for voltage support

A single line diagram of this transmission option can be found in Figure 7.3.

**Figure 7.3 | Transmission Option 3**



All three options involve a single-circuit supply to Red Lake and Pickle Lake. While the transmission lines can technically supply the demand forecast meeting thermal and voltage criteria, this configuration does not meet ORTAC load security criteria, which limits the amount of interrupted load following a contingency to 150 MW. Load growth beyond this threshold would require exemptions or additional infrastructure. Single-circuit supply also limits system reliability and resiliency, particularly during outages.

### 7.1.4 Option 3 – Double-circuit

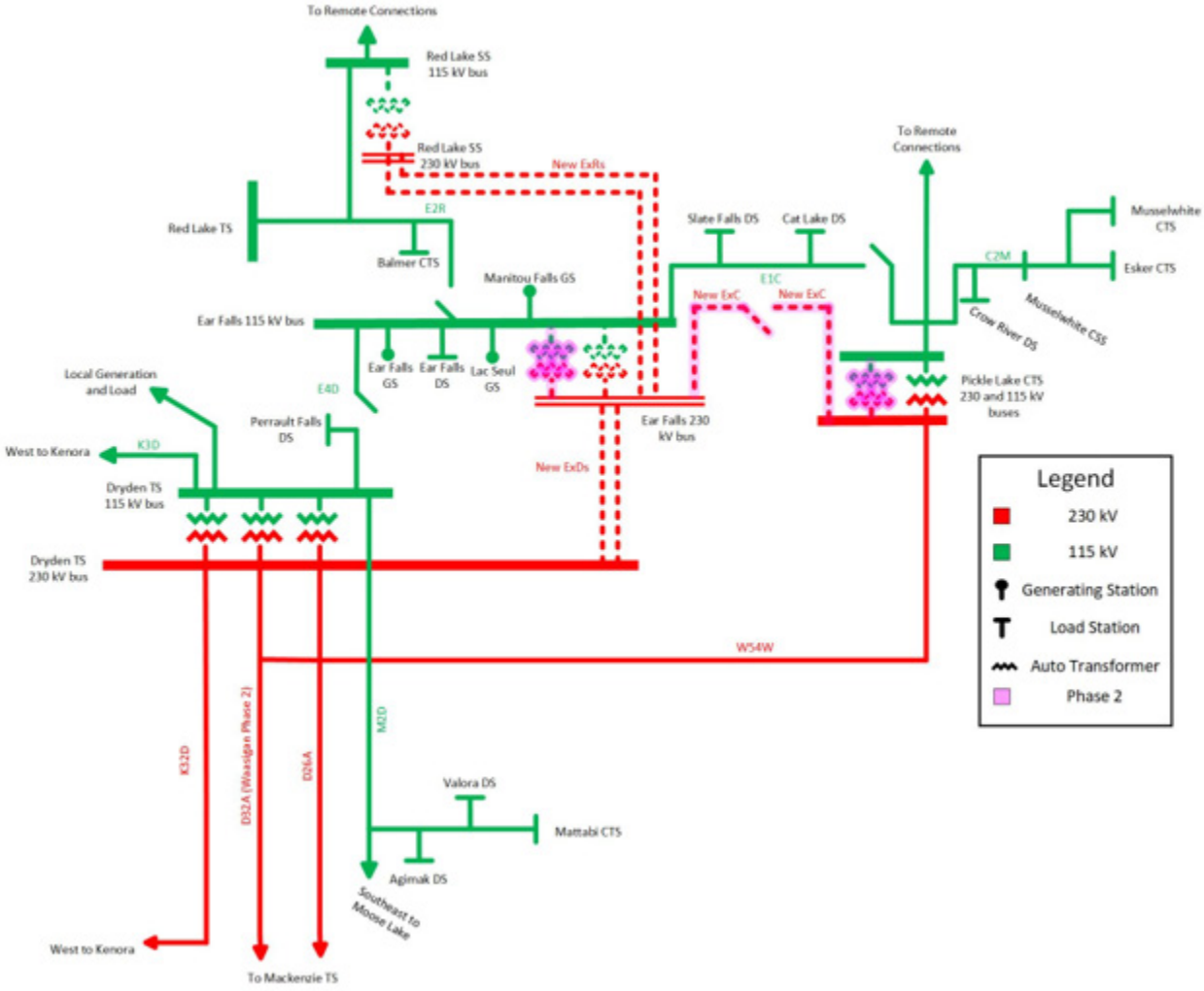
To enhance reliability and resiliency, a variation of Option 3 was studied that involved an upgraded double-circuit 230 kV line Dryden to Red Lake and reinforced supply to Pickle Lake. The following transmission upgrades summarize the scope of work needed for this option:

- A new 230 kV double-circuit transmission line from Dryden to Ear Falls (100 km long)
- A new 230 kV double-circuit transmission line from Ear Falls to Red Lake (62 km long)
- Reconfiguration of existing 115 kV circuits E4D and E2R to operate normally open

Supporting infrastructure includes:

- Two 230/115 kV auto-transformers at Ear Falls TS
- Two 230/115 kV auto-transformers at Red Lake SS
- Reactive compensation for voltage support

## Figure 7.4 | Transmission Option 3 Double Circuit



## 7.2 Options Comparison

Each transmission option was assessed against the applicable planning criteria under all-in service, N-1, and N-1-1 configurations, as detailed in Section 2.

### 7.2.1 Options Load Meeting Capability Comparison

**Table 7.1 | Option Load Meeting Capabilities**

| Transmission Option | LMC Flow into Dryden (MW) | LMC Flow into Pickle Lake (MW) | LMC Flow into Ear Falls (MW) |
|---|---|---|---|
| Option 1 | 381 | 404 | 150 or 355 (with criteria exemption) |
| Option 2 | 381 | 150 or 307 (with criteria exemption) | 150 or 355 (with criteria exemption) |
| Option 3 | 381 | 150 or 307 (with criteria exemption) | 150 or 355 (with criteria exemption) |
| Option 3 (double circuit) | 381 | 150 or 307 (with criteria exemption) | 437 |

Constructing a double-circuit transmission line upfront is generally more cost-effective than staging and building two separate single-circuit lines over time. In addition to the economic advantages, this approach also reduces the overall footprint of transmission infrastructure, minimizing environmental impact and land use. This principle informed the evaluation of Option 3 (Double-Circuit) as a more efficient and sustainable solution.

For Options 1 and 2, the LMCs for Dryden and Ear Falls are identical due to the shared 230 kV upgrade from Dryden to Red Lake. However, achieving these LMCs requires exemptions from ORTAC load security criteria, which limit the maximum amount of interruptible load to 150 MW for the loss of a single element. In contrast, Option 3 (Double Circuit) complies fully with ORTAC without requiring exemptions, offering a more resilient and standards-compliant solution.

The higher LMC for Pickle Lake in Option 1 is due to the inclusion of the new line parallel to the existing 230 kV transmission line W54W from Dinorwic JCT to Pickle Lake TS. This configuration meets all planning criteria without exemptions but comes at a significantly higher cost compared to Option 3 (Double Circuit) with a 230 kV E1C upgrade, as discussed in Section 7.2.2.

Additionally, the 115 kV circuits E4D and E2R (Dryden–Ear Falls and Ear Falls–Red Lake) are approaching end-of-life within the next 20 years. The IESO has studied these circuits as potential backup supply paths. Preliminary analysis suggests that uprating these circuits may be economically viable to enhance backup capability. The IESO will continue to monitor load growth in the Red Lake and Ear Falls areas to determine appropriate replacement strategies, which will be further explored in the next regional planning cycle beginning in Q3 2025.

### 7.2.2 Options Cost Comparison

Table 7.2 summarizes the cost of the three options, including the cost of double-circuit configuration for Option 3.

**Table 7.2 | Option Cost Comparison**

| Transmission Option | Estimated Capital Cost ($M) | New Circuit kms | Meets Red Lake area Reference Load Need Until | Meets Red Lake area High Load Growth Need Until |
|---|---|---|---|---|
| Option 1 | 2,490 | 724 | 2040 | 2034 |
| Option 2 | 1,560 | 422 | 2040 | 2034 |
| Option 3 | 720 | 262 | 2040 | 2034 |
| Option 3-dbl | 830 | 424 | 2050 and beyond | 2050 and beyond |

### 7.2.3 E1C upgrade and new customer connection point

As discussed in Section 6.2.4, circuit E1C is undergoing end-of-life replacement. It is recommended that Hydro One replace the conductor with a 411 kcmil conductor or better, which has a continuous rating of100 MVA. This upgrade will increase supply capacity and enable a proposed industrial customer to connect to E1C instead of their previously proposed location. This connection would be approximately 90 km shorter, resulting in a $150–$200 million reduction in transmission costs for the project. To support this connection, an additional 55 MVar shunt capacitor will be required at the new E1C connection point.

Following the customer connection, E1C should be operated normally open at Pickle Lake, consistent with recommendations in the 2023 Northwest IRRP. The upgraded conductor will also enhance E1C's ability to back up at least 50 MW of additional load in both Pickle Lake and Red Lake during contingencies, which provides system benefit.

To further improve reliability in the Pickle Lake and Red Lake areas, especially under high-growth scenarios, it may be necessary to reinforce the connection between these areas via the existing E1C corridor or by constructing a new 230 kV line parallel to the Wataynikaneyap W54W line. If E1C is upgraded to 230 kV, it could serve as a parallel supply path to Pickle Lake, complementing the Option 3 (Double-Circuit) transmission line from Dryden to Red Lake.

This configuration would allow the entire Pickle Lake area load to be backed up during outages. Additional reactive support (capacitive compensation) will be required at Pickle Lake TS, Ear Falls TS, and downstream corridors to enable full backup capability.

### 7.2.4 Transmission Options Conclusion

For the remainder of the analysis, Options 1, 2, and 3 were no longer considered, as they do not meet the demand in the long term, making them less resilient and cost-effective compared to Option 3 (Double Circuit), which meets all criteria and supports long-term growth through 2050 and beyond.

## 7.3 Non-Wires Alternatives (NWA)

In addition to evaluating transmission solutions for the North of Dryden sub-region, non-wires alternatives (NWAs) were also considered. The assessment focused on three sub-systems: Red Lake, Pickle Lake, and Dryden.

In the Red Lake area, forecasted load growth is expected to exceed the region's Load Meeting Capability (LMC) of 74 MW, creating a significant supply gap. While new Electricity Demand Side Management (eDSM) measures have been considered, their impact is relatively modest and provides only 5 MW of capacity savings by 2050. This limited contribution highlights the challenge of addressing the area's growing energy needs through demand-side solutions alone. As a result, there remains a substantial net requirement of 127 MW (755,995 MWh) by 2050, much of which is driven by expanding mining activity. Mining loads typically have a flat demand profile, requiring consistent supply across all hours and seasons, with peak demand occurring during winter months.

Various resource options were considered to create a range of NWA costs for North of Dryden. The following NWA economic assessments were studied:

1. Natural gas
2. Biomass
3. Solar + Wind + BESS
4. Wind +BESS
5. Solar + BESS

Although the NWA options 4 and 5 were studied, not every load requirement of every hour (8760 hourly needs) would be served. As a result, these two options were ruled out from the NWA analysis.

Some assumptions were also made during the economic assessment which include:

- Various emitting and non-emitting resource options were considered creating a range of costs for Non-Wire Alternative's (NWA's).

- Emitting resources considered included Combine Cycle Gas Turbine (CCGT) and Biomass facilities, with overnight capital costs, fixed operating and maintenance (FOM), biomass fuel and variable operating and maintenance (VOM) sourced from 2024 Annual Technology Baseline (ATB) data by The National Renewable Energy Laboratory (NREL).
- Natural gas fuel costs and carbon costs assumptions from 2025 Annual Planning Outlook (APO).
- NWA emitting and non-emitting levelized costs are based on 2024 ATB data from NREL whereby the values are converted to Canadian (CAD) 2025$.
- System benefits based on the 2025 APO Capital Expansion (CapEx) portfolio https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/APO-2025-Marginal-Energy-Costs-and-Capacity-Costs.xlsx
- All dollar figures are $2025 Real, the inflation rate is assumed to be 2% per year, and the social discount rate is 4% Real.
- Net present value (NPV) is considered from 2026 to 2102, with the transmission option commencing in 2033 for 70 yrs and the NWA aligning with this transmission timeline. The transmission costs consist of the Red Lake portion of the transmission options.

Further details on assumptions made for NWA can be found in Appendix D.

Table 7.3 presents a comparative economic analysis of various supply options for meeting future electricity needs in the Red Lake area. It includes both transmission and non-wires alternatives (NWAs), evaluating each option across several key dimensions: total utility cost, system benefit, net impact to ratepayers, land requirements, and the percentage of need and load served.

A key metric in this analysis is System Benefit, which refers to the option's contribution to Ontario's overall resource adequacy and energy requirements. In other words, it reflects how much the resource helps meet provincial-level electricity demand not just local needs. This is particularly important when considering NWAs, as some options may offer broader system value beyond the immediate region.

**Table 7.3 | Economic Assessment for Wires and Non-Wires Alternatives**

| Options | Total Cost (Utility) | System Benefits | Net Benefit/Cost to Ratepayer | Land Requirement | % of Need Served | % of Load Served |
|---|---|---|---|---|---|---|
| Transmission Option 3 | $647 M | $0 M | -$647 M | ~500–1000 hectares/5–10 $km^2$ | 100.0% | 100.0% |
| Natural Gas | $1,378 M | $1,378 M | $0 M | ~20–40 hectares/0.2 - 0.4 $km^2$ | 100.0% | 100.0% |
| Biomass | $2,755 M | $1,585 M | -$1,170 M | ~20–40 hectares/0.2 - 0.4 $km^2$ | 100.0% | 100.0% |
| Solar + Wind + BESS | $3,295 M | $2,923 M | -$372 M | ~6,572 hectares/65.7 $km^2$ | 99.2% | 99.7% |
| Wind + BESS | $11,118 M | $10,092 M | -$1,026 M | ~48,895 hectares/ 489 $km^2$ | 99.0% | 99.6% |
| Solar + BESS | $6,035 M | $5,193 M | - $842 M | ~4,344 hectares/ 43.4 $km^2$ | 97.6% | 98.9% |

Note: All values are Net Present Values (NPVs), from 2026 to 2102, at a 4% social discount rate, in $2025 CAD.

Based on Table 7.3, transmission option 3 (as a single circuit) has the least transmission cost to ratepayers ($647 M). However, natural gas net cost has the least cost option for the Red Lake area of $0 M based on the 2024 National Renewable Energy Laboratory's (NREL) cost for a Combine Cycle Gas Turbine (CCGT) facility. Due to the later introduction of Option 3 built as a double circuit, a full economic assessment was not completed. However, it would be expected to have higher costs (of approximately 25%) than the single circuit option with a similar distribution of costs to benefits (i.e., no system benefits). Natural gas overnight capital cost from NREL is likely understated as these costs do not capture incremental costs associated with locating in the northwest region of Ontario. In addition, the natural gas supply needs for a 127 MW gas plant may not be feasible, since Red Lake is supplied by a gas distribution lateral off the TransCanada Energy Mainline. Further analysis is required to assess the true feasibility of implementing this option. In contrast, the biomass option has the highest cost to ratepayers in comparison to all the listed options, with a net benefit of $1.2 B.

Within the non-emitting NWA options, Wind + Solar + BESS has the least net benefit cost of $372 M, which is a lower net cost relative to the transmission option 3 of $647 M. This option would require about 65.7km$^2$ of land, which would need to be discussed with the local area community to assess for siting feasibility and acceptance. The options Wind + BESS and Solar + BESS are also provided to illustrate the possible land requirement range. Nonetheless, these options will not be able to meet 100% of the hours of the sub-region, which is an important factor to consider.

Overall, when evaluating non-wires alternatives, a natural gas generator presents comparable initial utility costs to those of transmission option 3. While the generator may offer certain system benefits, it also raises several significant concerns that make the transmission alternative a more attractive and viable recommendation. Key issues include the challenges of load restoration during generator outages, unserved load risks, and the absence of interconnection for backup supply between the Pickle Lake and Red Lake area. Further uncertainty exists regarding the exact location of the proposed plant, construction risks, the alignment of pipeline infrastructure, and the level of community acceptance. Additionally, reliance on a gas plant would not resolve the broader transmission limitations, as it only addresses the needs of the Red Lake area under the reference scenario. In the high-demand scenario, a generator of the size considered in this study would be insufficient to meet the projected capacity requirements. Finally, reliance on natural gas generation to meet demand, on a continuous basis, would not be compliant with the Clean Electricity Regulations (CER) enacted under the Canadian Environmental Protection Act. These regulations establish a performance standard of 30 tonnes of CO2 emissions per gigawatt-hour (T/GWh). Should additional needs arise in both the Pickle Lake and Red Lake areas, further reinforcement, either through transmission expansion or an additional generation facility in the Pickle Lake area, would be necessary. Although both options have strong stakeholder support, the transmission alternative remains the more favourable option due to these unresolved concerns associated with the natural gas option.

## 7.4 Recommendation

The transmission options were evaluated based on several key metrics, including:

- Cost to ratepayers
- Ability to serve forecasted load
- Compatibility with existing infrastructure
- Potential for future expansion
- System reliability and resilience

Option 3, when built as a single-circuit transmission line, is capable of meeting the reference load forecast up to the medium term. However, under this configuration, nearly all load in the Red Lake and Ear Falls areas would be radially supplied via a single circuit. In the event of a contingency, this load would be interrupted, and while circuit E4D could provide backup, it is insufficient to restore full supply. Over the long-term, this configuration violates ORTAC load security criteria, which limits the amount of interrupted load following a contingency to 150 MW.

### Recommended Solution: Option 3 – Double-Circuit

To address these concerns, the IRRP recommends Option 3 built to a double-circuit transmission line, consisting of the following elements:

- Construct a double-circuit 230 kV transmission line from Dryden TS to Ear Falls TS (100 km)
- Construct a double-circuit 230 kV transmission line from Ear Falls TS to Red Lake SS (62 km)
- Install two new 230/115 kV autotransformer at Ear Falls TS
- Install two new 230/115 kV autotransformer at Red Lake SS
- Reconfigure existing 115 kV circuits E4D and E2R to operate normally open
- Install 40 MVar shunt capacitors at:
- Red Lake SS
- Ear Falls TS
- 230 kV side of Pickle Lake TS

The proposed 230 kV transmission line does not align well with the Transmitter Selection Framework (TSF) due to the urgent need to increase supply capacity in the Red Lake area. The TSF best suits projects with longer lead times (≥ 6 years) to accommodate a competitive procurement process. Given the time-sensitive nature of this project, proceeding outside the TSF would better support timely delivery, system reliability and support economic development.

### Benefits of the Recommended Option

This option:

- Meets regional electricity needs through 2050 and beyond, under reference, high, and extreme demand scenarios
- Improves reliability and reduces load interruptions in the North of Dryden sub-region
- Supports connection of new resources, including hydroelectric, biomass, and other generation, by reducing connection costs and enabling power transfer to the broader grid
- Enhances system robustness and resilience, while remaining compliant with planning criteria
- Reduces long-term costs, as the incremental cost of building a double-circuit line is significantly lower than constructing a parallel single-circuit line later
- Leverages existing rights-of-way, where feasible, to minimize environmental and land-use impacts.

Considering the construction challenges in Northern Ontario and the incremental cost advantages, the double-circuit configuration provides enhanced reliability for municipalities, remote communities, and industrial customers. It also prepares the transmission system for future expansion to accommodate high and extreme load growth in the Pickle Lake area.

# 8. Community and Stakeholder Engagement

Engagement is critical in the development of an Addendum. Providing opportunities for input in the regional planning process ensures that the views and perspectives of Indigenous communities, municipalities, stakeholders, communities, market participants, customers, and the general public, are considered in the development of the Plan, helping to lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the North of Dryden Addendum.

## 8.1 Engagement Principles

The IESO's External Relations Engagement Framework and the Indigenous Engagement Framework are built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

**Figure 8.1 | IESO'S Engagement Principles**

The IESO's engagement principles[11] help to ensure that all interested parties are aware of and can contribute to the development of this Plan. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

## 8.2 Engagement Approach

To ensure that the Plan reflects the needs of Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public, engagement involved:

- Leveraging the North of Dryden engagement webpage to post updated information, engagement opportunities, meeting materials, input received and the IESO responses to feedback,
- Holding targeted discussions with municipalities, associations and mining industry to help inform the engagement approach for this planning cycle and to understand feedback and perspectives at key milestones,
- Hosting a series of public webinars at major junctions in the Plan's development to share plan details, understand feedback and answer questions
- Carrying out communications and other engagement tactics to enable broad participation through email and IESO's weekly Bulletin updates.

As a result, the engagement for the North of Dryden Addendum included:

- A dedicated webpage[12] on the IESO website to post all webinar materials, feedback received and IESO responses to the feedback throughout the engagement process,
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin,
- Hosting public webinars at major milestones in the plan development to share plan details, understand feedback, and answer questions,
- Targeted one-on-one outreach with Indigenous communities, municipalities, and stakeholders to ensure that their identified needs are addressed.

## 8.3 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 an email to impacted municipalities, Indigenous communities, industry stakeholders, and municipal associations to announce the commencement of the development of an Addendum to the 2023 Northwest Integrated Regional Resource Plan.

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[11] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

[12] https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-North-of-Dryden-Sub-Region

An invitation was sent to targeted municipalities to discuss the draft demand forecast and electricity needs in the region. A virtual meeting was held early in the process and feedback was received, which centered on the need to ensure that municipal energy planning, economic development and industrial growth (mining) were included in the development of the Addendums demand forecast. In addition, reliability remained a paramount concern within this region. The IESO had further engagement with the Northwest Energy Task Force (NW-ETF) to help further inform the Addendum demand forecast.

A second in-person meeting was held with elected officials and municipal staff from impacted municipalities to provide an update on the progress of the Addendum. During the meeting, the IESO shared the demand forecast, electricity needs, and preliminary options screening results.

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.

A third virtual meeting was held with elected officials and municipal staff from impacted municipalities, as well as the NW-ETF, to provide an update on the options evaluation and draft recommendations and seek feedback. Municipalities and the NW-ETF were supportive of the draft recommendations for the Addendum and what the Plan means for the growth in their communities and economic development. NW-ETF noted how pleased they were with how collaborative the regional plan was. The Municipality of Red Lake and the NW-ETF shared concerns that long lead times for transmission infrastructure may not align with the timing of planned industrial projects.

Two public webinars were held at key stages during the Plan's development to give interested parties an opportunity to hear about progress and provide feedback to each component of the Plan. The first public webinar was held on May 7, 2025 to share the draft demand forecasts, needs, and options screening. The webinar, attended by a cross-representation of community representatives, municipalities, associations, businesses, and other stakeholders, and written feedback was collected over an approximately two-week comment period after the webinar, also sought feedback from interested stakeholders and community representatives.

A second public webinar was held on July 30, 2025 to share the options analysis and draft recommendations, and sought feedback from interested stakeholders and community representatives. The webinar was attended by a cross-representation of community representatives, municipalities, associations, businesses, and other stakeholders, and written feedback was collected over an approximately two-week comment period after the webinar.

The public webinars invited input on:

1. The electricity demand forecasts, the electricity needs for the region and potential options to meet the identified needs.
2. The analysis of options and draft Addendum recommendations.

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

- Cost allocation methodology for new transmission infrastructure.
- Consideration of local developments, growth plans and reliability concerns in demand forecasts particularly in communities with limited capacity.
- Consideration of non-wire alternatives to meet needs, as well as existing resources in the region where contracts are due to expire.
- Concern about long lead times for transmission infrastructure and the resulting impacts on planned industrial project timelines, along with feedback that the Addendum should address interim needs as new transmission is developed.
- General support for the draft Option 3 Double Circuit recommendation.
- Request that government declare Addendum recommendation a priority project to expediate the new transmission line.

Each engagement session received strong participation and interest with a cross-representation from stakeholders and community representatives. Feedback received as a result of each engagement meeting and webinar was considered throughout the development of each milestone of the Addendum.

All interested parties were kept informed throughout this engagement initiative via email to Northwest region subscribers, municipalities, and Indigenous communities, in addition to webpage updates. All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's North of Dryden Addendum engagement webpage.

Discussions during the Addendum engagement showed strong interest in further exploring the potential development of the mining sector, opportunities to unlock regional economic growth, and alternative energy solutions to meet local needs—particularly as communities and industries face capacity constraints or transition toward 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, including an upcoming Northwest Integrated Regional Resource Plan.

## 8.4 Involving Municipalities in the Plan

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 Addendum. At major milestones in the Addendum process, meetings were held with targeted municipalities in the region to discuss key issues of concern, including forecasts, 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 Addendum process.

Throughout these discussions valuable feedback was received concerning anticipated growth in the mining industry and local communities, including:

- Municipality of Red Lake is preparing a Red Lake Gap Analysis Study that could be used as an input to better understand the residential and commercial growth expected in the next 3–5 years, due to enhanced transportation infrastructure that would connect neighboring communities.
- Northwest Energy Task Force shared their demand forecast for the region to be used as an input into the finalization of the Addendums demand forecast.
- Advocacy that more electricity infrastructure was needed in the Northwestern region to support current and future residential and industrial growth.

These insights have been invaluable to the IESO, as they support an understanding of local growth and accurate electricity demand forecast scenarios, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply. To that end, ongoing discussions will continue to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

## 8.5 Engaging with Indigenous Communities

The IESO remains committed to ongoing, effective dialogue with Indigenous 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 that may be potentially impacted or may have an interest based on treaty territory, traditional territory or traditional land use to participate in webinars that were held on:

- Addendum Letter of Commencement November 29, 2024
- May 7, 2025
- July 30, 2025

The following First Nations communities were invited to the webinars:

- Animakee Wa Zhing No. 37
- Animbiigoo Zaagi'igan Anishinaabek
- Anishinaabeg of Naongashiing (Big Island)
- Anishinabe of Wauzhushk Onigum
- Aroland
- Asubpeeschoseewagong First Nation
- Bearskin Lake
- Big Grassy River (Mishkosiminiziibiing)
- Biigtigong Nishnaabeg
- Biinjitiwaabik Zaaging Anishinaabek
- Bingwi Neyaashi Anishinaabek
- Cat Lake
- Constance Lake
- Deer Lake
- Eabametoong
- Eagle Lake
- Fort Severn
- Gakijiwanong Anishinaabe Nation
- Ginoogaming First Nation
- Gull Bay First Nation
- Iskatewizaagegan No. 39
- Kasabonika Lake
- Keewaywin
- Kiashke Zaaging Anishinaabek
- Kingfisher Lake
- Kitchenuhmaykoosib Inninuwug
- Koocheching First Nation
- Lac des Mille Lacs
- Lac Seul
- Long Lake No. 58
- Marten Falls
- McDowell Lake
- Michipicoten
- Mishkeegogamang
- Missanabie Cree
- Muskrat Dam Lake
- Namaygoosisagagun
- Naotkamegwanning
- Neskantaga
- Netmizaaggamig Nishnaabeg (Pic Mobert)
- Nibinamik
- 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
- Sachigo Lake
- Sandy Lake
- Shoal Lake No. 40
- Slate Falls
- Wabaseemoong
- Wabauskang
- Wabigoon Lake
- Wapekeka
- Washagamis Bay (Obashkaandagaang)
- Wawakapewin
- Webequie
- Weenusk
- Whitesand
- Whitewater Lake
- Wunnumin Lake

The following Tribal Councils and Provincial Territorial Organizations (PTOs) were invited to the webinars:

- Anishinabek Nation, Union of Ontario Indians
- Chiefs of Ontario
- Grand Council Treaty #3
- Independent First Nations Alliance (IFNA)
- Keewaytinook Okimakanak/Northern Chiefs Council
- Matawa First Nations Management
- Matawa First Nations Tribal Council
- Nishnawbe Aski Nation
- Shibogama First Nations Council
- Windigo First Nations Council

The following Métis communities were invited to the webinars:

- Métis Nation of Ontario
- Red Sky Independent Métis Nation

The IESO also had one-on-one meetings with Indigenous communities for opportunities to provide input on their own planning and priorities to ensure that these plans were taken into consideration in the development of this Addendum.

Feedback on IESO engagement efforts from Indigenous communities included:

- Support for the construction of a new 230kV line from Dryden to Red Lake, as the recommended option due to risks that First Nation communities north and south of Red Lake will face development restrictions in a time when new housing, community infrastructure, and services are badly needed.
- Projects will require the consent and meaningful participation of First Nations to move forward with construction. Hydro One is best positioned to develop the Project and has committed to meaningful First Nations participation under its "First Nation Equity Partnership Model."
- Land rights and ownership need to be respected and Manito Aki Inaakonigewin (MAI), the "Great Earth Law," needs to be followed and adhered to for all proposed activities and projects occurring in Treaty #3. The options did not show the potential negative environmental footprint on the land itself. The environmental impacts need to be discussed and addressed prior to new transmission going ahead.

### 8.5.1 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.

# 9. Conclusion

The Northwest IRRP Addendum identifies electricity system needs in the North of Dryden sub-region over a 25-year planning horizon from 2025 to 2050. It examines near-, medium-, and long-term requirements.

Based on the analysis, the IESO recommends the development of Transmission Option 3, constructed to a double-circuit standard with appropriate reactive support. This solution balances cost-effectiveness with reliability and scalability, ensuring the system can adapt to future growth.

The Study also recommends that the Working Group continue to monitor demand growth, particularly in the Pickle Lake areas, and triggering planning for further reinforcements from Ear Falls towards Pickle Lake as load materializes under high-growth scenarios. Sensitivity analyses conducted in this Addendum have established load meeting capability thresholds that should be used to trigger future regional planning activities.

The IESO will continue to plan for high-growth scenarios in the next cycle of regional planning for Northwest Ontario, which commenced in Q3 2025. This upcoming cycle will explore transmission options aligned with ongoing bulk system studies and assess the feasibility of non-wires alternatives.

The Working Group will meet regularly to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, the plan may be revisited through an amendment or by initiating a new regional planning cycle ahead of the standard five-year schedule mandated by the Ontario Energy Board (OEB).

# Appendix A – 2023 Northwest IRRP

This Addendum is built on the 2023 Northwest Integrated Regional Resource Plan ("2023 NW IRRP"). The 2023 NW IRRP, Appendices, and Data Tables can be found on IESO's Northwest regional planning engagement website.

# Appendix B – Additional Figures

## B.1 Single Line Diagrams

**Figure B.1 | Option 1**

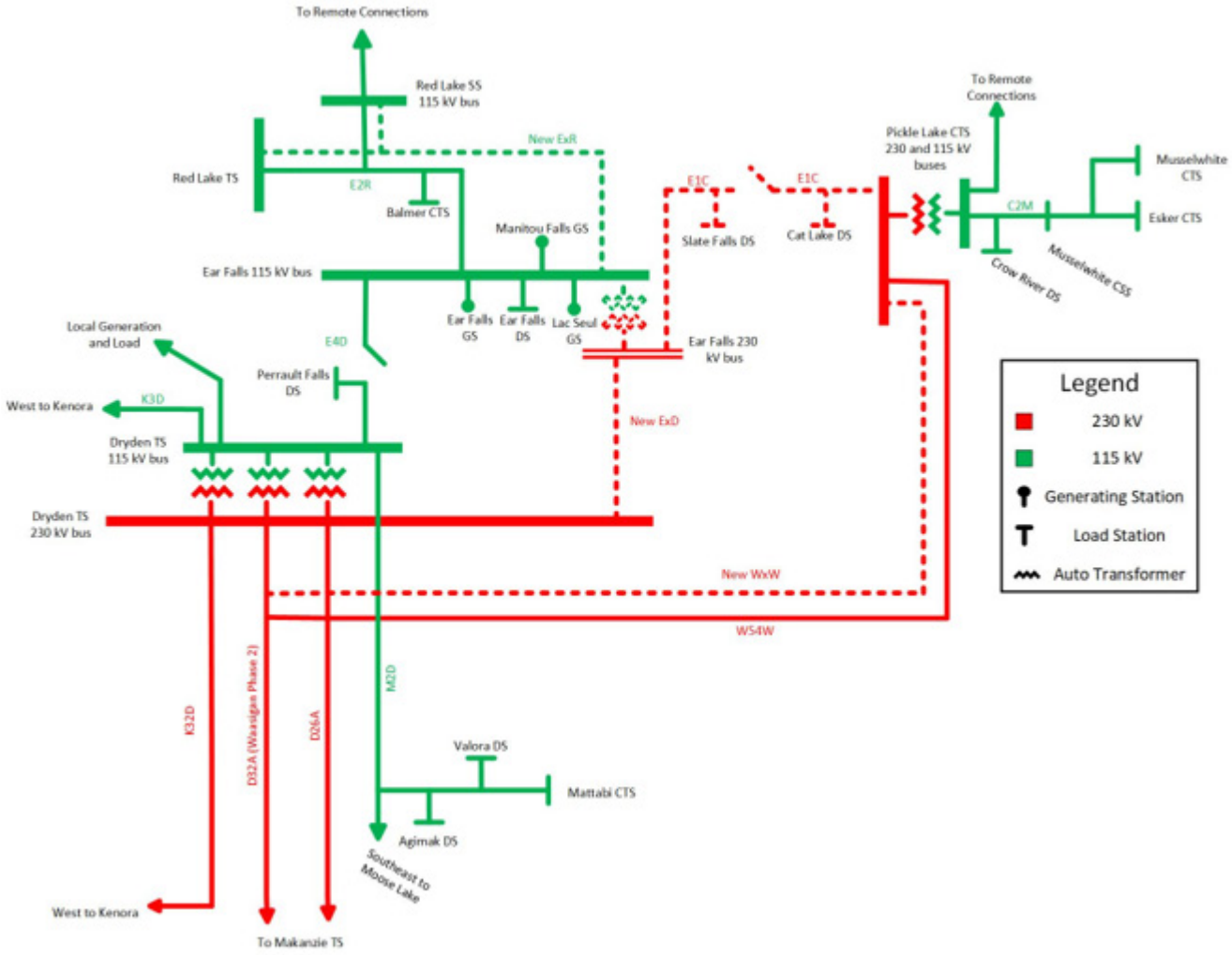
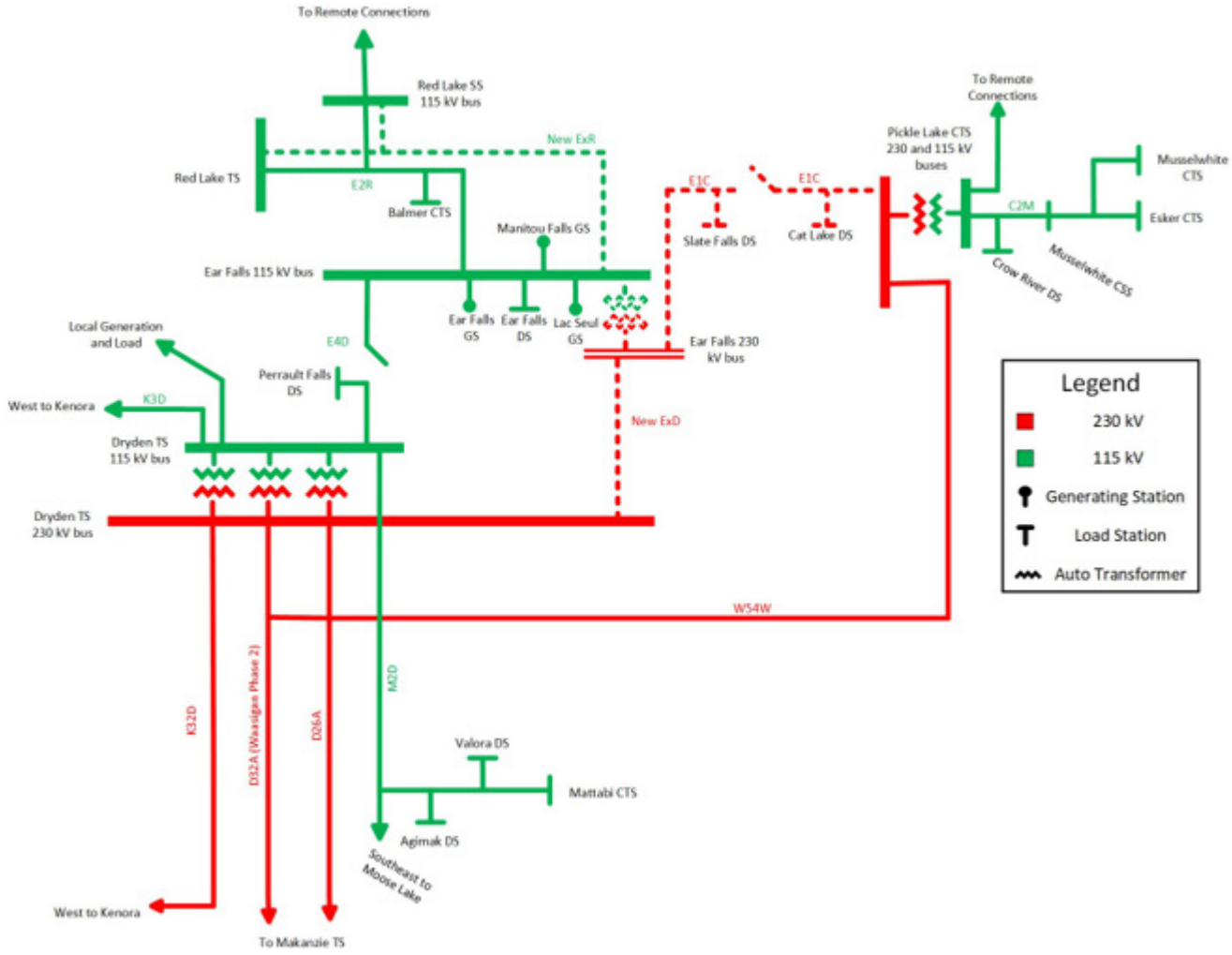
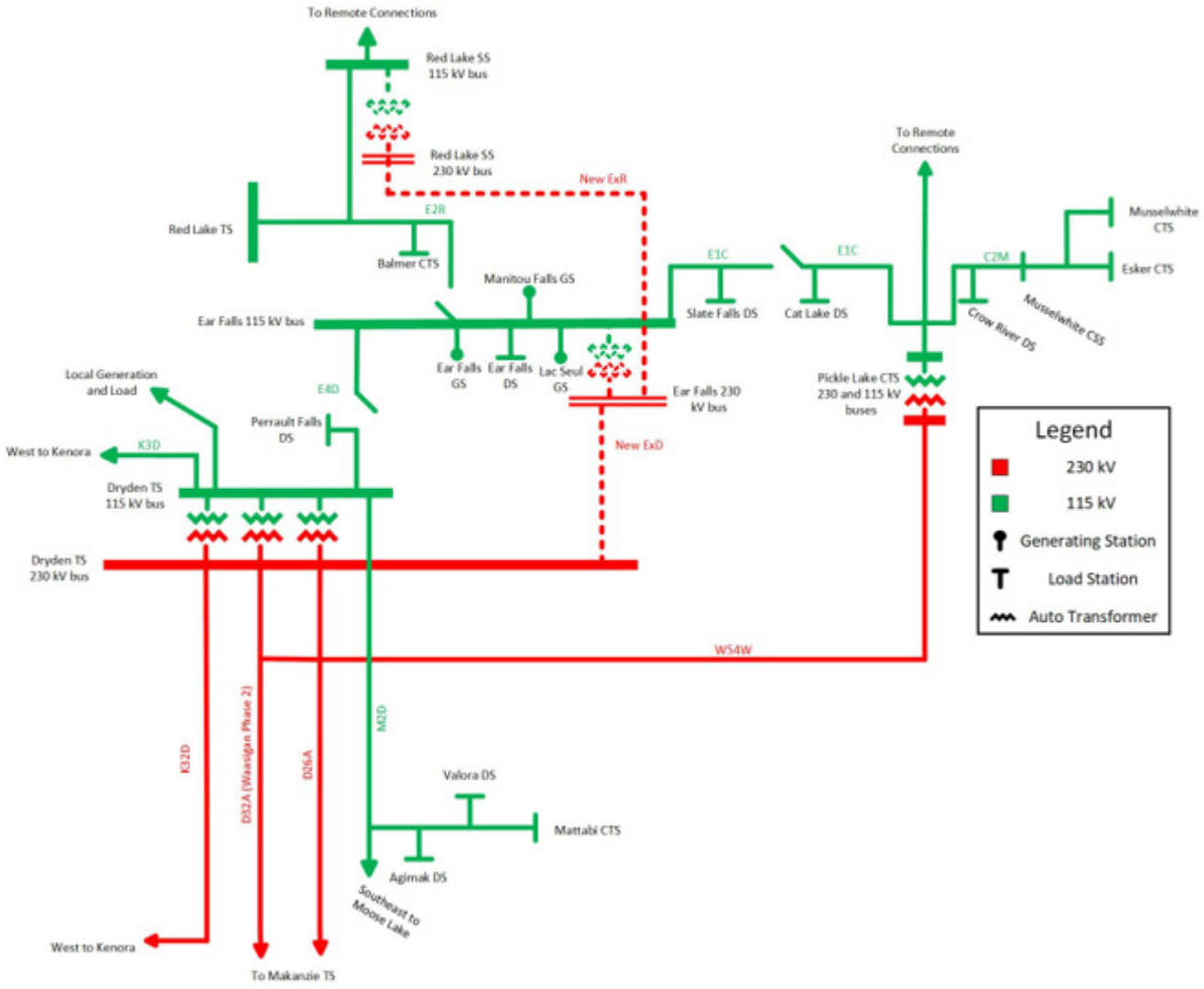


**Figure B.2 | Option 2**



## Figure B.3 | Option 3



# Appendix C – Options Reactive Support Requirements

It should be noted that these reactive support requirements are in addition to reactive support recommended at the connection point of certain industrial customers. In particular the 60 MW customer that is connecting in the interlakes area will require 55 Mvar of reactive support, and the 23 MW customer connecting in the Watay Power operated Red Lake area will require 10 Mvar of reactive support. This support is needed to maintain transfer capability in these regions, as large industrial loads can negatively affect voltages, particularly in weaker parts of the system.

## C.1 Option 1

The reactive support requirements for option 1 for the reference load case are as follows:

- 40 Mvar @ 220kV capacitor at Red Lake SS
- 40 Mvar @ 220kV capacitor at Ear Falls TS
- 40 Mvar @ 220kV capacitor at Pickle Lake TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar of support to respect voltage change criteria.

The reactive support requirements for option 1 for the high load case are as follows:

- 40 Mvar at Ear Falls TS
- 40 Mvar at Dinorwic CSS
- 100 Mvar at Pickle Lake TS 230 kV
- 200 Mvar at Wawa TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar and STATCOMS with over 100 Mvar of reactive support to respect voltage change criteria.

## C.2 Option 2

The reactive support requirements for option 2 for the reference load case are as follows:

- 40 Mvar at Red Lake SS
- 40 Mvar at Ear Falls TS
- 40 Mvar at Pickle Lake TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar of support to respect voltage change criteria.

The reactive support requirements for option 2 for the high load case are as follows:

- 40 Mvar at Ear Falls TS
- 40 Mvar at Dinorwic CSS
- 100 Mvar at Pickle Lake TS 230 kV
- 200 Mvar at Wawa TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar and STATCOMS with over 100 Mvar of reactive support to respect voltage change criteria.

### C.3 Option 3

The reactive support requirements for option 3 for the reference load case are as follows:

- 40 Mvar at Red Lake SS
- 40 Mvar at Ear Falls TS
- 40 Mvar at Pickle Lake TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar of support to respect voltage change criteria.

The reactive support requirements for option 3 for the high load case are as follows:

- 40 Mvar at Ear Falls TS
- 100 Mvar at Dinorwic CSS
- 100 Mvar at Pickle Lake TS 230 kV
- 200 Mvar at Wawa TS 230 kV

The IESO recommends that the transmitter avoid procuring single switchable shunts with over 40 Mvar and STATCOMS with over 100 Mvar of reactive support to respect voltage change criteria.

# Appendix D – Non-Wires Alternatives Economic Assessment Assumptions

The following assumptions were made for the Non-Wires Alternatives Analysis:

- Various emitting and non-emitting resource options were considered creating a range of costs for Non-Wire Alternatives (NWAs)
- Emitting resources that were considered included: Combine Cycle Gas Turbine (CCGT) and Biomass facilities, overnight capital costs, fixed operating and maintenance (FOM), biomass fuel and variable operating and maintenance (VOM) sourced from 2024 Annual Technology Baseline (ATB) data by the National Renewable Energy Laboratory (NREL).
- Natural gas fuel costs and carbon costs assumptions from 2025 Annual Planning Outlook (APO)
- NWA emitting and non-emitting levelized costs are based on 2024 ATB data from NREL whereby the values are converted to Canadian (CAD) 2025$
- System benefits are based on the 2025 APO Capital Expansion (CapEx) portfolio
- All dollar figures are $2025 CAD Real, the inflation rate is assumed to be 2% per year, and the social discount rate is 4% Real
- Net present value (NPV) is considered from 2026 to 2102, with the Transmission (Tx) option commencing in 2033 for 70 yrs and the NWA aligning with this Tx timeline
- Land Requirements Supplemental Information:
    - Land area of Red Lake is 600 $km^2$
    - 1 Hectares = 0.01 $km^2$
    - Wind Land Requirement = 34 Hectares/MW[13]
    - Solar Land Requirement = 3.04 Hectares/MW[14]
    - Battery Land Requirements = 0.65 Hectares/200MWh (or 0.003 Hectares/MWh)[15]
    - Natural Gas Requirements = According to Natural Gas Association, the average natural gas plant requires between 20 and 40 acres of land
    - Biomass facility land requirement is assumed to equal the natural gas land requirement provided above

[13] Source: Land-Use Requirements of Modern Wind Power Plants in the United States (nrel.gov)
[14] Source: https://www.nrel.gov/docs/fy13osti/56290.pdf
[15] Source: Goreway - Battery Energy Storage System - Capital Power

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