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October 3, 2025

ADDRESS & EMAIL

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Attention: Ritchie Murray, Acting Registrar

Re: **EB-2025-0192: Wataynikaneyap Power LP ("WPLP") – Application for Approval of 2026 Electricity Transmission Rates (the "Application") – Applicant's Interrogatory Responses**

We are legal counsel to Wataynikaneyap Power LP ("WPLP"), which is the applicant in the above-referenced proceeding. On behalf of WPLP, and in accordance with Procedural Order No. 1 issued on August 22, 2025, we are pleased to provide WPLP's responses to interrogatories from Ontario Energy Board staff.

Please note that none of the responses require confidential treatment. Please also note that the attachments to OEB staff interrogatories 34, 36, 38 and 39 consist of live Excel documents that are being filed separately.

If you have any questions, please do not hesitate to contact me at the number shown above.

Yours truly,

Jonathan Myers

cc: Ms. Margaret Kenequanash, WPLP
Mr. Duane Fecteau, WPLP

BOARD STAFF – 1

Reference: Exhibit A-3-1 / page 2

Preamble: The application states that:

> WPLP continues to be engaged in commercial discussions with its EPC contractor, regarding costs under the EPC Contract in relation to COVID-19 impacts and related access matters, the outcome of which will ultimately be recorded in the previously approved EPC COVID-Related Construction Costs Deferral Account.

Question(s):

a) Please briefly discuss the current status of the commercial discussions with the EPC contractor, Valard. Please provide any updates to the planned schedule of the commercial discussions.

b) Does WPLP have a revised estimate for when these discussions are expected to conclude? If not, please explain the factors contributing to the delay in reaching a resolution.

c) Please provide details in regards to any arbitration process that has been pursued by WPLP, including associated timelines and key issues under consideration.

d) When does WPLP expect to receive the additional CIAC contribution? In which rate year's revenue requirement application, does WPLP expect to request disposition of the EPC COVID Account.

Response:

a) Over the past year, WPLP and Valard have met several times on a without prejudice basis to discuss the cost overruns incurred by Valard.

Valard has provided cost information, on a without prejudice basis, related to the cost overruns. This information has been reviewed by WPLP, to assess whether the costs relate to a force majeure event and are costs required to be paid under the EPC Contract. Currently the discussions between WPLP and Valard are primarily around the approach to allocate costs and cost responsibility in light of the force majeure provisions of the EPC Contract.

Based on the information provided by Valard, the COVID-19 relief sought by Valard will relate to the Line to Pickle Lake and the Remote Connection Lines and will cover all construction years.

b) WPLP and Valard met most recently on September 10, 11 and 25, 2025 to continue their discussions in an attempt to reach resolution, and will continue to meet into Q4 2025 as required. If a settlement can be achieved without the use of arbitration, a resolution to the commercial discussions could potentially occur in time to allow WPLP to seek disposition of the EPC-Related Costs Deferral COVID Account in the multi-year revenue requirement application for a test period beginning in 2027. If arbitration is required, a decision in the arbitration could take approximately 18-30 months from the start of arbitration, based on normal arbitration timelines.

c) No arbitration process has been pursued by either WPLP or Valard at this time as the parties continue negotiating.

d) Assuming a settlement can be achieved on the timelines noted in response to (b) above, WPLP expects to receive the additional CIAC contribution in Q4, 2026 and request disposition of the EPC COVID-Related Costs Deferral Account in year 1 of the multi-year revenue requirement application, i.e. 2027. If a settlement is not achieved (whether in accordance with the above timelines or otherwise) and/or arbitration is required, WPLP will seek mid-term clearance of such account during its first multi-year rate term, as agreed to in the approved settlement in EB-2024-0176.

   As explained in Exhibit H-2-2, at pp. 6-7 and in Exhibit I-4-1, WPLP expects “that in its next revenue requirement application after recording the final settlement amount in the EPC COVID Account, WPLP would bring forward for disposition the balance thereof, together with carrying charges (AFUDC), to rate base. After the OEB undertakes a prudence review and approves the rate base addition, a second CIAC under the Federal Funding Framework will be triggered and the independent Trust would then provide to WPLP a second CIAC based on and to fully offset the approved amount of the rate base addition.”

BOARD STAFF – 2

Reference: Exhibit A-3-1 / page 3 / footnote 4

Preamble: The above reference states that for Muskrat Dam First Nation, which has historically been served by an Independent Power Authority (IPA), the transmission system assets up to the connection point were energized by WPLP in 2023, but community connection is pending IPA upgrades and information transfers, and is therefore expected to occur in 2025.

Question(s):

a) What is the current status of the community connection for Muskrat Dam First Nation? What is the reason for the delay comparing to other community connections?

b) Is there any update as to when the above noted pending IPA upgrades and information transfers will be completed?

Response:

a) As at September 30, 2025, Muskrat Dam First Nation is not connected to the WPLP transmission system. The community continues to be in discussions with Indigenous Services Canada on the transfer agreement, which deals with both the necessary IPA upgrades and information transfers.

b) Based on progress to date, WPLP is unable at this time to provide a timeline on the Muskrat Dam First Nation IPA upgrades and information transfers.

BOARD STAFF – 3

Reference: Exhibit B-1-1 / page 2

Preamble: The reference states:

> In respect of four of the communities to be served by the Transmission System (Muskrat Dam First Nation, Poplar Hill First Nation, North Spirit Lake First Nation and Keewaywin First Nation), while all WPLP line and station facilities up to the connection points to these communities were energized and available for use by 2024, the distribution systems in the communities, over which WPLP has no control, were not yet ready to receive service at the time transmission service became available.

Question(s):

a) Please provide a status update on the WPLP line and station facilities up to Muskrat Dam First Nation, Poplar Hill First Nation, North Spirit Lake First Nation, and Keewaywin First Nation. Please also state which of the communities' distribution systems are currently receiving service from WPLP's transmission system and the date at which they began receiving service. If any of the communities' distribution systems are not currently receiving service, please state when WPLP expects them to begin receiving service.

b) When were these connections included in rate base, how much rate base do they represent?

Response:

a) As stated on p. 2 of Exhibit B-1-1, the WPLP line and station facilities up to the connection points of all four communities were energized and available for use by 2024. The connection dates for Poplar Hill First Nation, North Spirit Lake First Nation and Keewaywin First Nation are identified in footnote 5 of Exhibit B-1-1. As explained in response to Board Staff IR 2, Muskrat Dam First Nation is capable of being connected to the WPLP transmission system once the local distribution system upgrades and information transfers are completed. Those aspects are beyond WPLP's control and, based on discussion with Indigenous Services Canada, the connection timeline is unknown at this time.

b) The Poplar Hill First Nation, North Spirit Lake First Nation and Keewaywin First Nation assets were included in WPLP's 2024 rate base additions as this is when the assets were energized and considered used or useful. The costs for the relevant segments (RS, S1,

ZV, Y1, V1) and substations (S,V,Y) amounted to $114.7 million of rate additions in 2024.

The Muskrat Dam First Nation assets were included in WPLP's 2023 rate base additions as this is when the assets were energized and considered used or useful. The costs for segment E1 and substation E[1] amounted to $35.8 million. WPLP has excluded line segment DE from this amount as it is required to supply communities North of Muskrat Dam First Nation.

[1] WPLP notes Station E is also required to supply the communities North of Muskrat Dam First Nation. Power is flowing through the power transformers and station service systems to power all of the 115 kV relays and controls for the EF and EG lines.

BOARD STAFF – 4

Reference: Exhibit B-1-2 / page 7

Preamble: The reference states:

> WPLP is in the preliminary stages of calculating, trending and verifying health index calculations using ENGIN for a population of assets that have all been placed in service in the past 1-7 years. As a result, meaningful asset health index calculation and trending are not yet available and WPLP will endeavour to provide this information in a future revision of this AMP.

Question(s):

a) For which asset categories does WPLP currently have meaningful asset health indices calculated at this time, if any?

b) Please provide all asset health indices that have been calculated at this time.

c) When does WPLP expect to have asset health indices calculated for all of its assets?

Response:

a) WPLP has meaningful asset health indices calculated for the following asset classes:

- Station Ancillary
- Station Battery
- Station Battery Charger
- Station Building
- Station Circuit Breaker
- Station Current Transformer
- Station Power Transformer
- Station Protection
- Station Reactor
- Station Service Transformer
- Station Surge Arrester
- Station Switch
- Station Voltage Transformer

b) See Attachment ‘A’ for WPLP’s Health Indices that have been calculated as of December 31, 2024. Please note that WPLP is transitioning from a Staging (testing) environment in ENGIN to a Production environment and, since filing the application, has been able to validate the reasonability of all inspection entries and calculated results up to and

including 2024, but the review and validation process for 2025 inspection results remains in progress.

c) WPLP expects to have asset health indices calculated for all of its asset classes by Q2 2026. However, for certain asset classes that are subject to less frequent inspections, such as lower-voltage wood pole lines (25 and 44 kV, for which there is a 6-year ground inspection cycle) additional time may be required to validate and refine the health index calculations.

Attachment 'A' - Overall Health Index for Substations by Asset Class:

Category	Very Poor	Poor	Fair	Good	Very Good
Station Ancillary	0	0	0	0	44
Station Battery	0	0	1	4	37
Station Circuit Breaker	0	0	1	4	88
Station Current Transformer	0	0	0	0	44
Station Power Transformer	0	0	0	0	31
Station Protection	0	0	2	1	581
Station Reactor	0	0	1	1	19
Station Service Transformer	0	0	0	4	39
Station Surge Arrester	0	0	0	0	169
Station Switch	0	0	2	8	320
Station Voltage Transformer	0	0	0	0	86

BOARD STAFF – 5

Reference: Exhibit B-1-3 / pages 3-4
IESO "Northwest Region Integrated Regional Resource Plan Addendum"

Preamble: WPLP states that the Independent Electricity System Operator (IESO) will be releasing an addendum to the North of Dryden Integrated Regional Resource Plan in Summer 2025. The addendum became available on Aug 31.

Question(s):

a) Please file a copy of the IESO document "Northwest Region Integrated Regional Resource Plan Addendum" for the record of this proceeding.

b) What impact, if any, does the addendum has on WPLP's regional planning considerations?

Response:

a) See Attachment 1. WPLP notes that following the publication of the addendum to the North of Dryden IRRP on August 31, 2025, the IESO also published a Scoping Assessment Outcome Report for the Northwest Ontario Region on September 19, 2025, which is included as Attachment 2.

b) The addendum recommends that WPLP install: (1) two new 250 MVA 230/115 kV autotransformers at Red Lake SS; (2) a 40 MVAR shunt capacitor at Red Lake SS; and (3) a 40 MVAR shunt capacitor at Pickle Lake TS. Since the timing need identified for these additional assets is 2028, WPLP intends to include the required investments in its multi-year revenue requirement application to be filed in 2026 for a period beginning with the 2027 test year, noting that there will likely be refinements to scope, cost estimates and forecasted in-service dates as these projects are further developed.

Northwest Region Integrated Regional Resource Plan Addendum

North of Dryden Sub-Region
August 2025

ieso
Connecting Today.
Powering Tomorrow.

Disclaimer

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Table of Contents

List of Figures

List of Tables

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

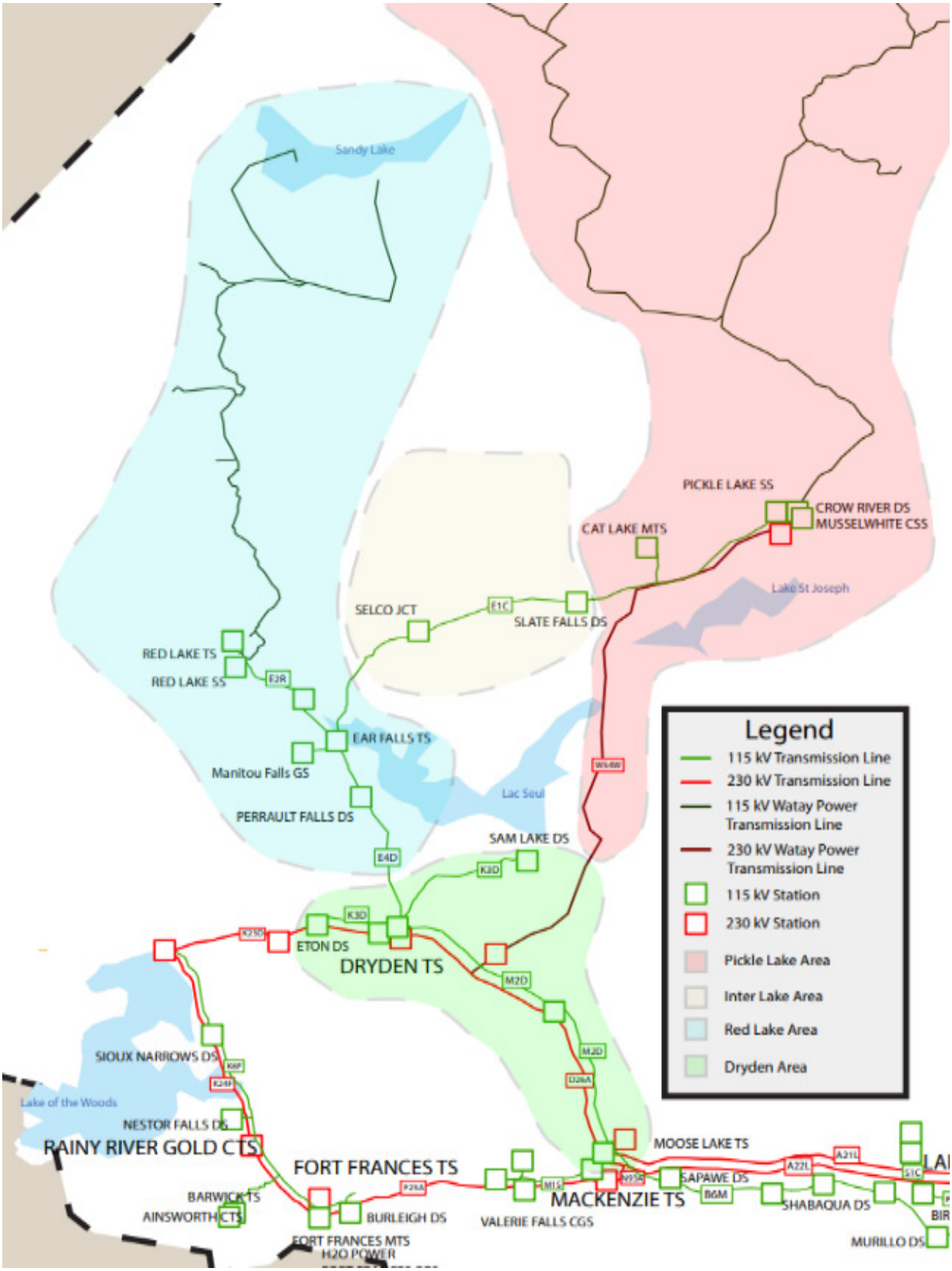
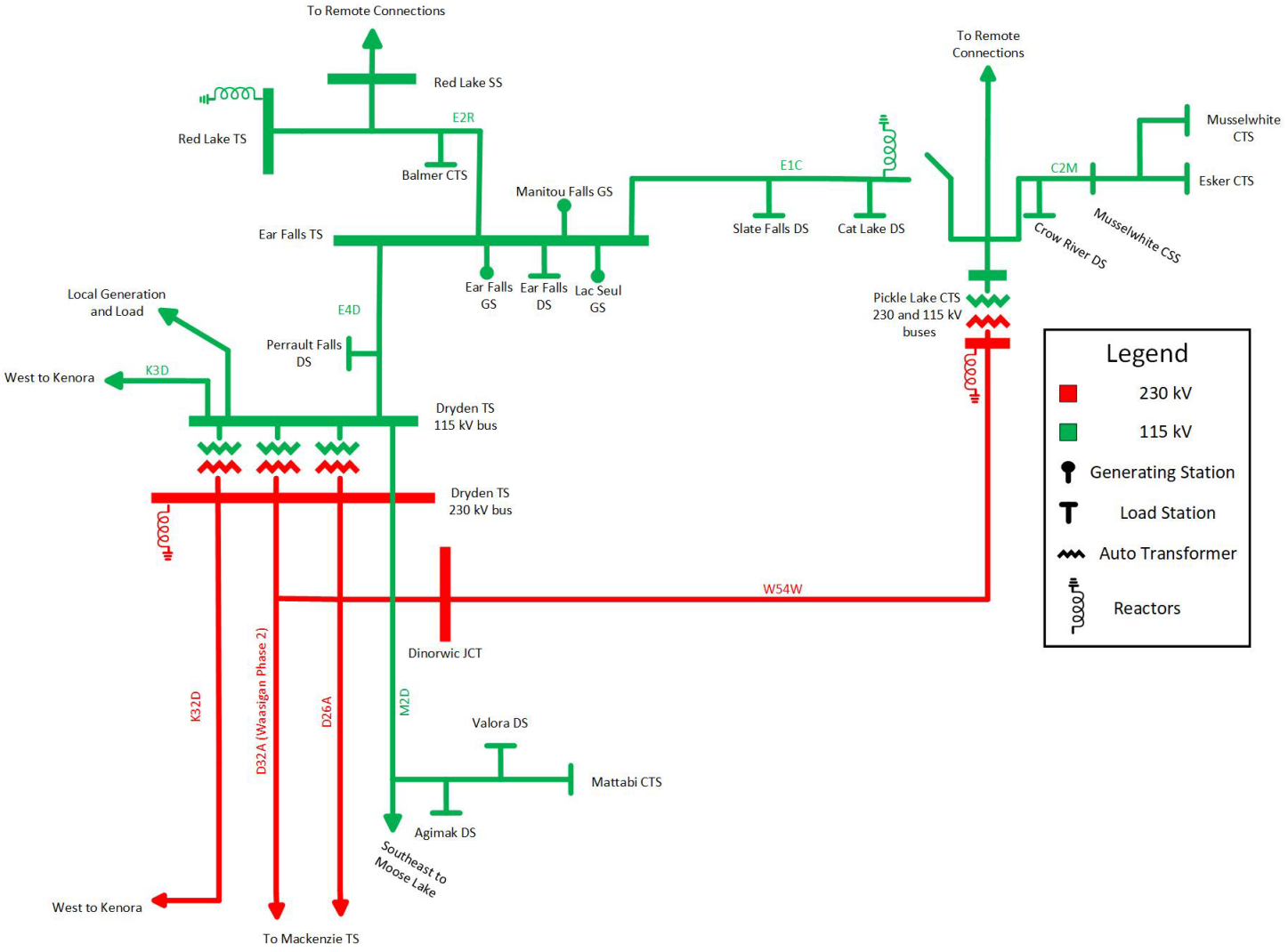


Figure 1.2 | Current Electricity Infrastructure in the North of Dryden Sub-Region



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

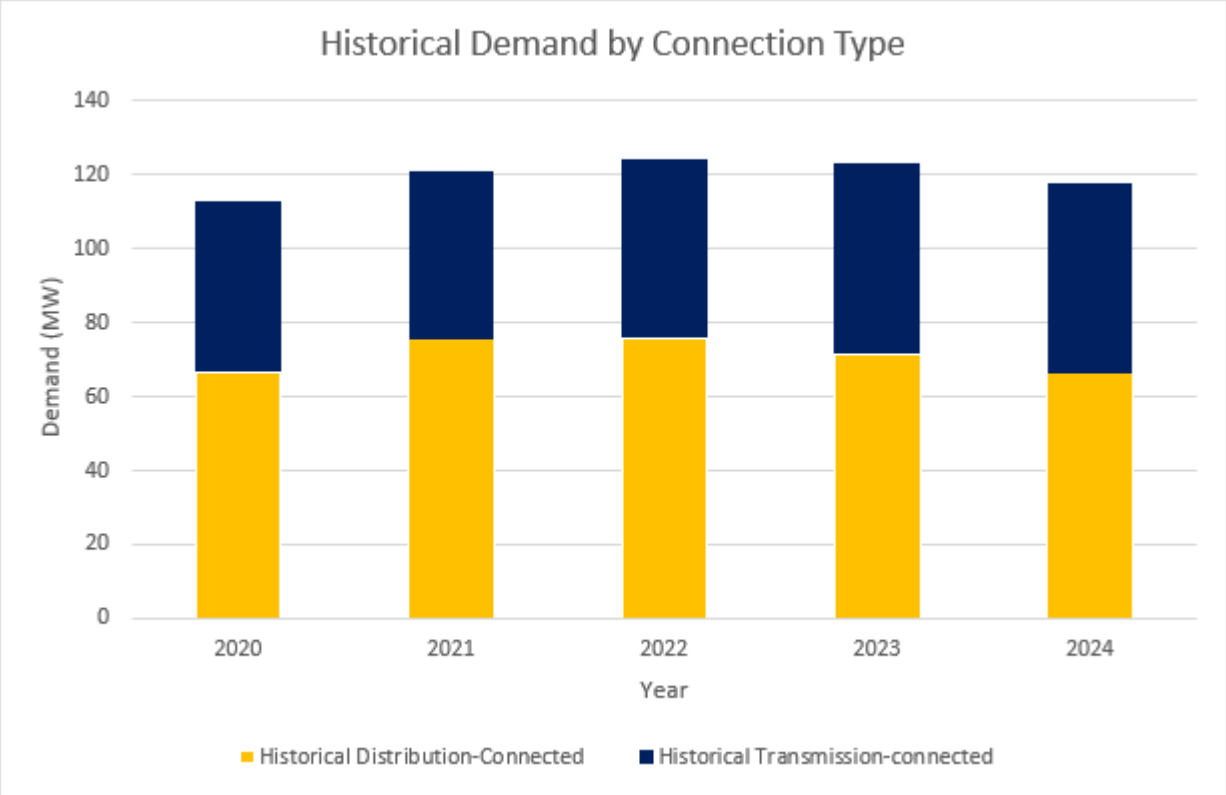
Figure 5.1 illustrates net and gross historical demand over the past five years in the North of Dryden sub-region. Historically, distribution-connected customers have accounted for approximately 60% of peak demand, with the remainder served through transmission connections.

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

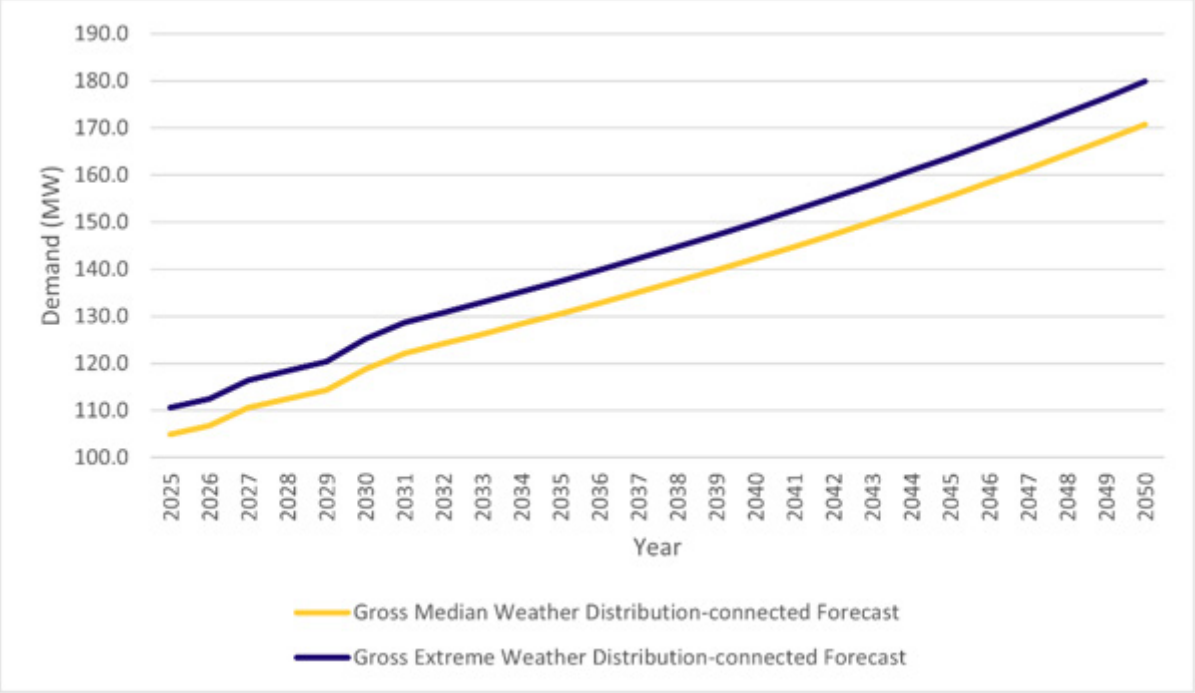
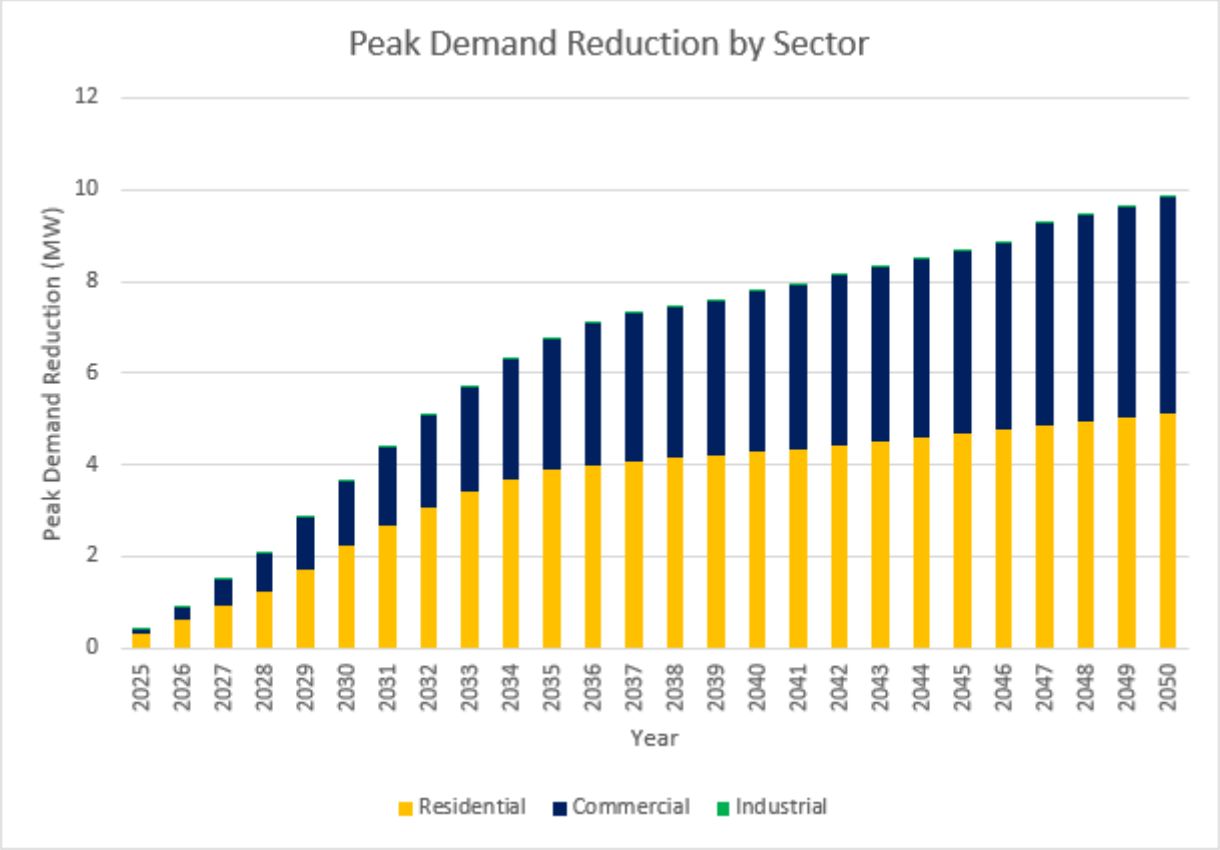


Figure 5.3 | Contribution of Conservation to Forecast



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.

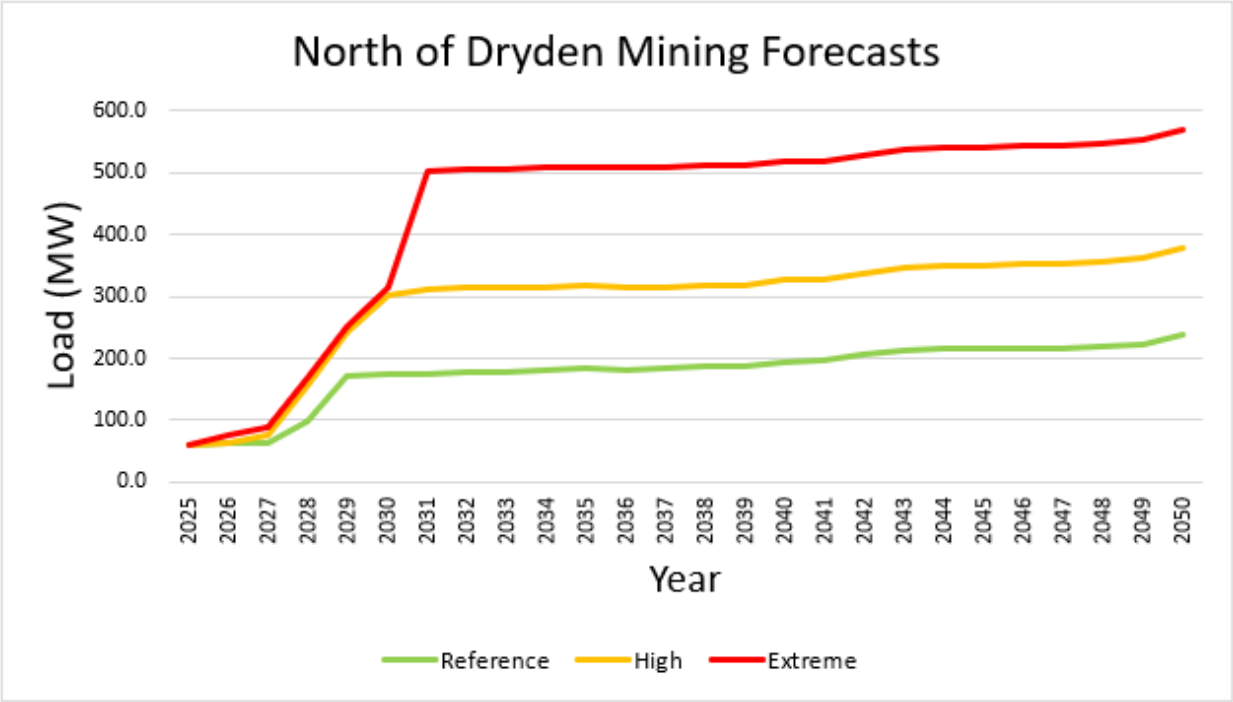
The mining forecast is presented across three scenarios, Reference, High, and Extreme to reflect varying levels of project certainty. The likelihood of a project materializing is informed by factors such as data reliability, project development stage, and expected in-service dates. The IESO also consulted 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 • 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) • Aligned with 2025 Annual Planning Outlook Reference scenario
High	Reference Scenario plus: • Mining projects that have more uncertainty in timing.
Extreme	High Scenario plus: • 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.

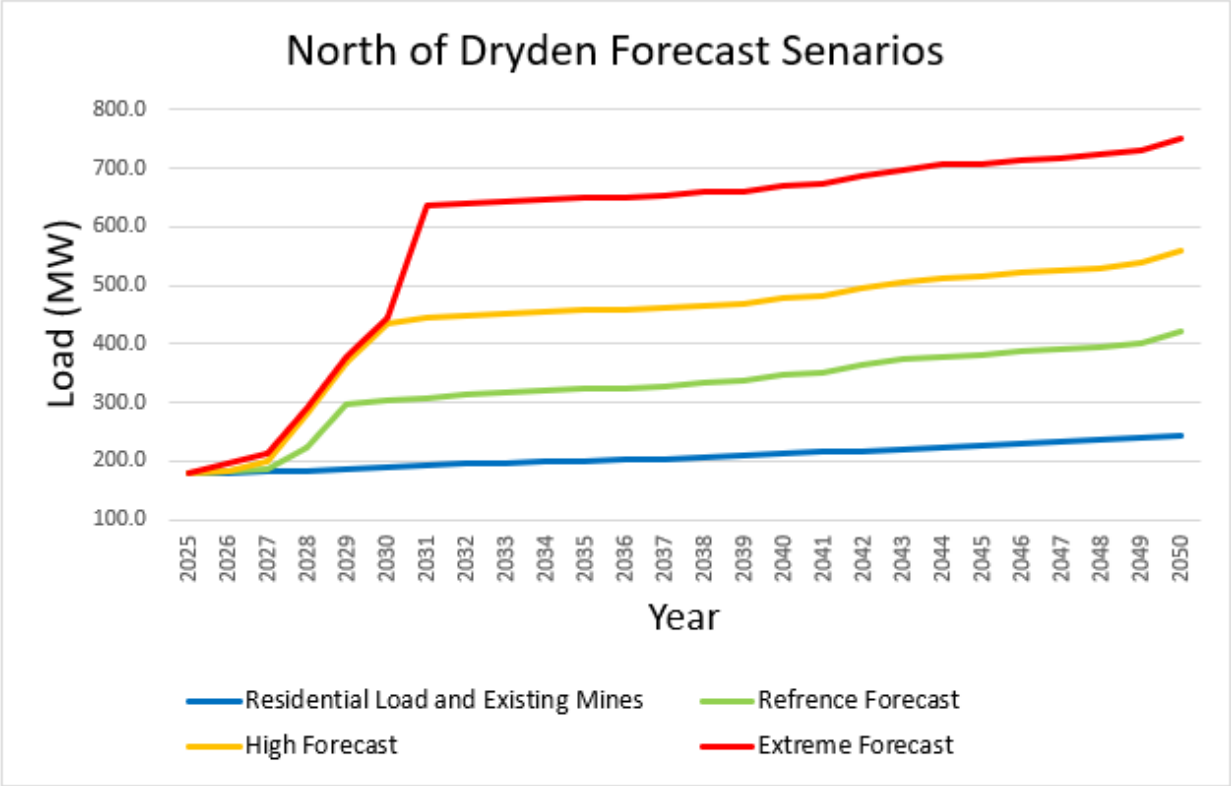
Figure 5.4 | Mining Demand Forecast



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.

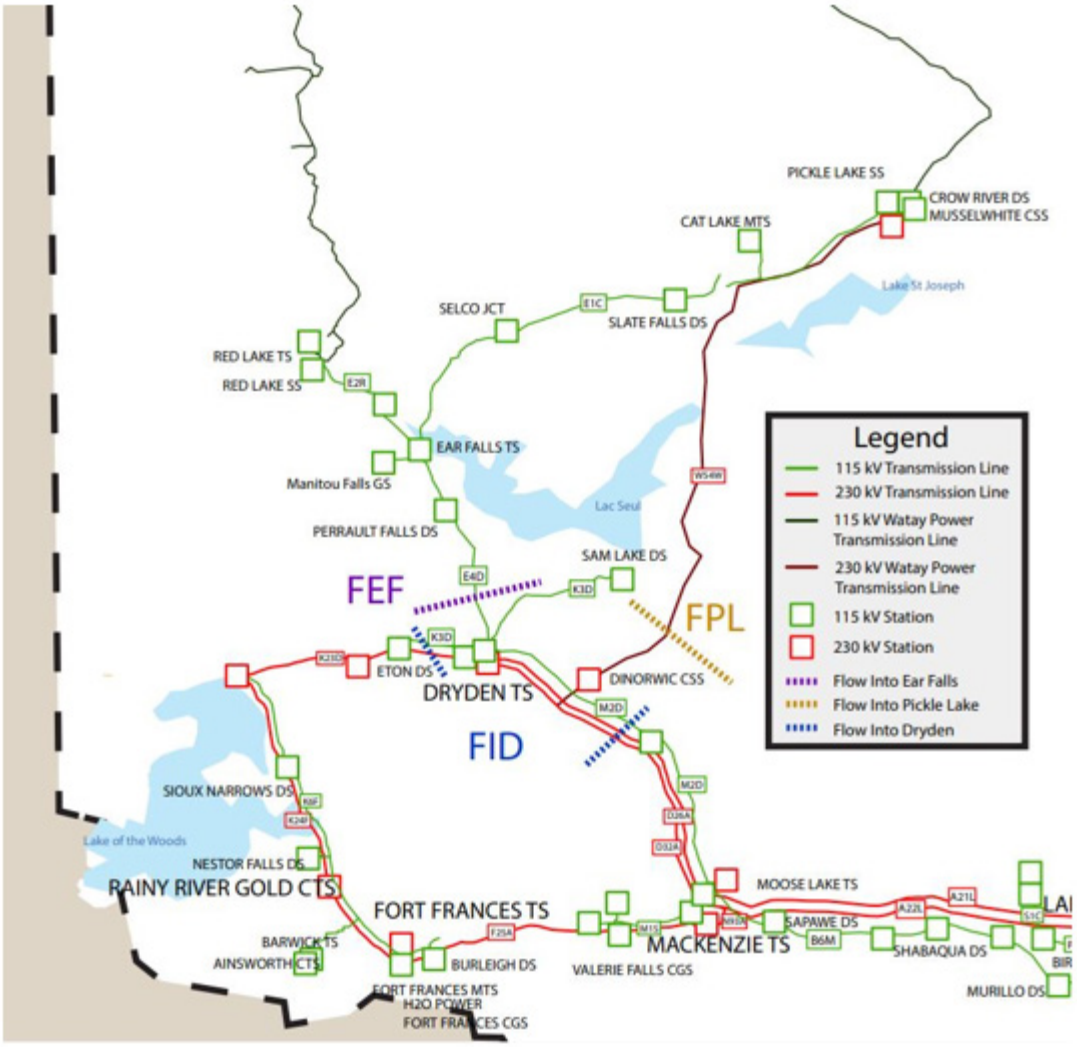
- **Load Security and Restoration Needs**
  These describe the system's ability to minimize the impact of major transmission outages and restore service within reasonable timeframes. Load security refers to the amount of supply interrupted during an outage (e.g., loss of both circuits on a double-circuit 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



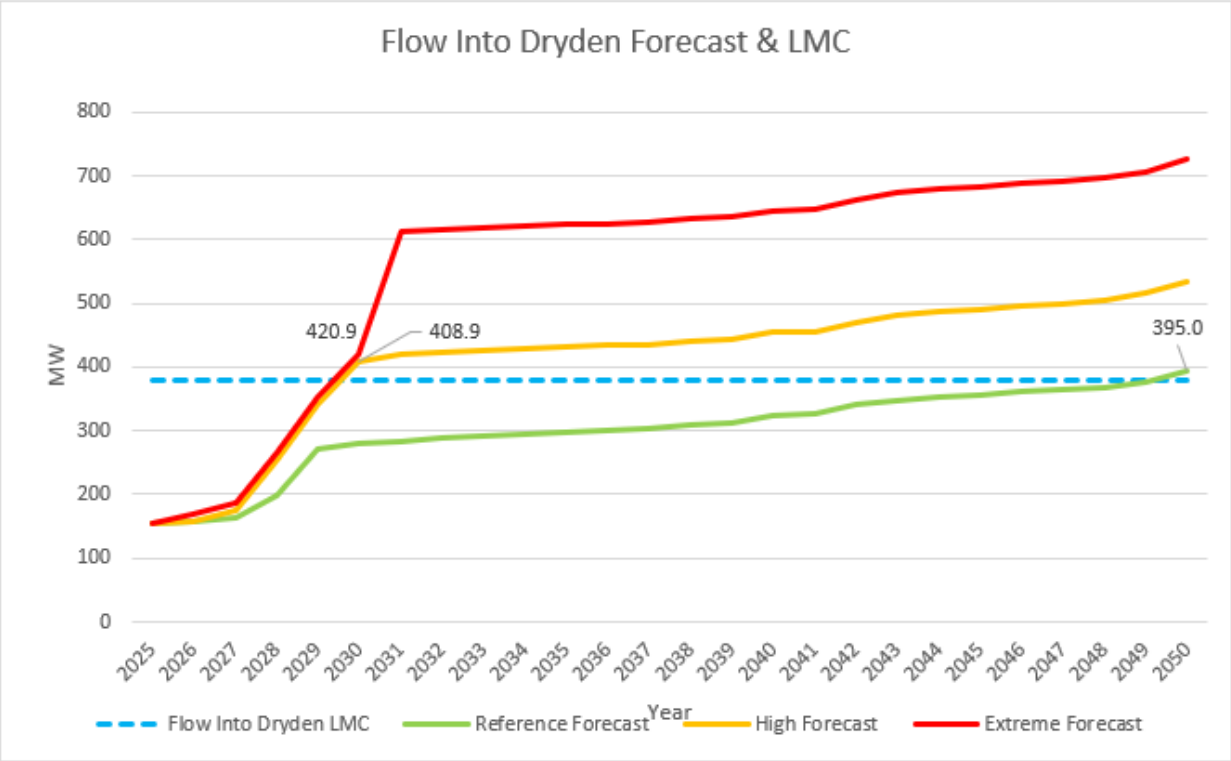
6.2.1 Flow into Dryden

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

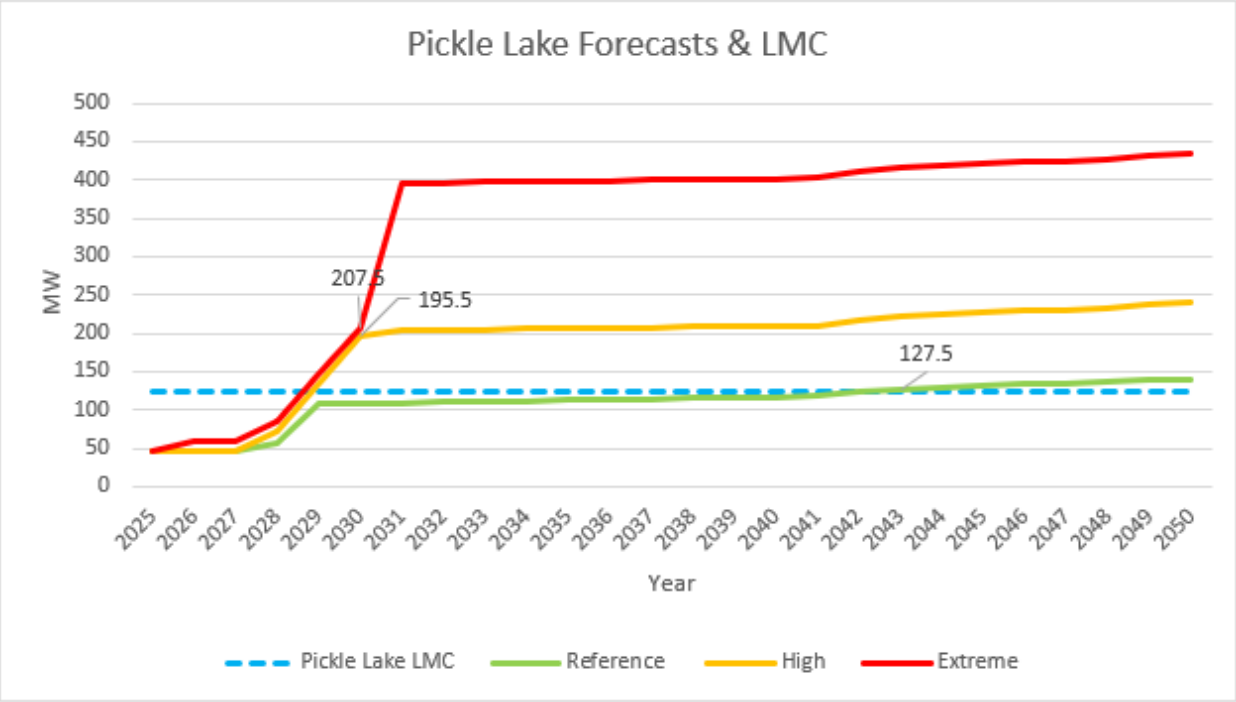
The Flow into Pickle Lake (FPL) interface is defined by the radial supply via circuit W45W, with circuit E1C providing a partial backup path through the Red Lake system. The current load meeting capability (LMC) of the Pickle Lake area is approximately 125 MW, constrained by pre-contingency voltage limits 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.

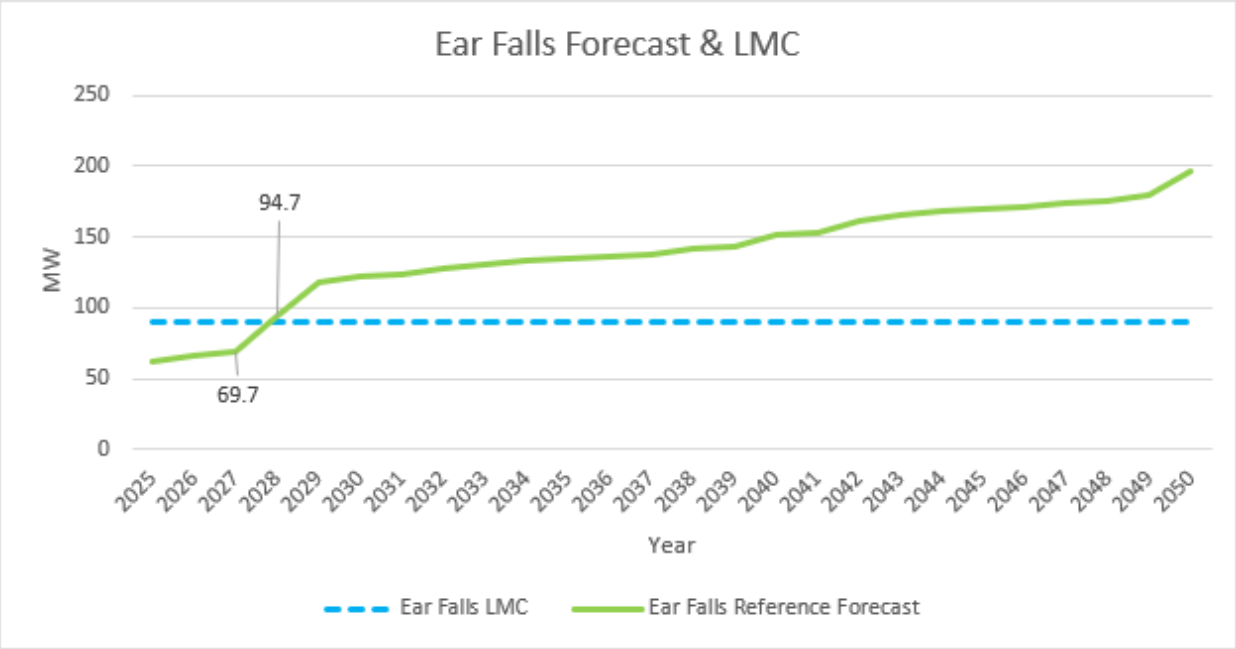
Figure 6.3 | Flow into Pickle Lake Load Meeting Capability and Forecast Scenarios



6.2.3 Flow into Ear Falls

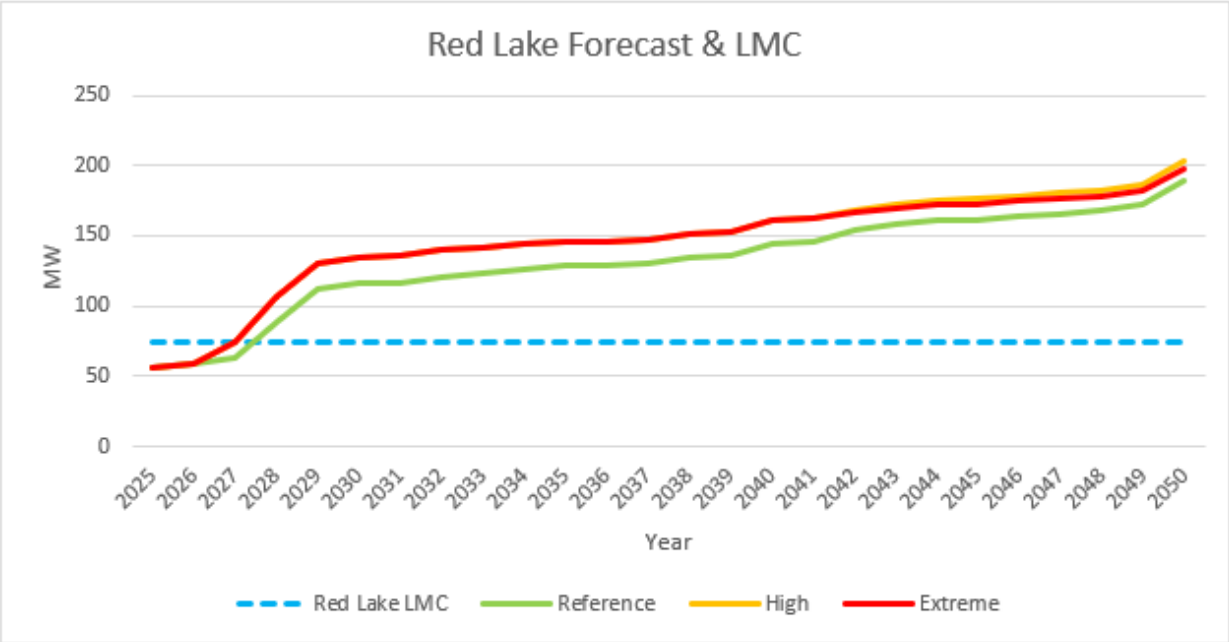
The Flow into Ear Falls (FEF) interface is defined by radial supply via circuit E4D, with circuit E1C offering potential backup. The current LMC for this interface is 90 MW, limited by the summer thermal rating of E4D. Figure 6.4 shows forecasted demand across the FEF interface relative to this threshold.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

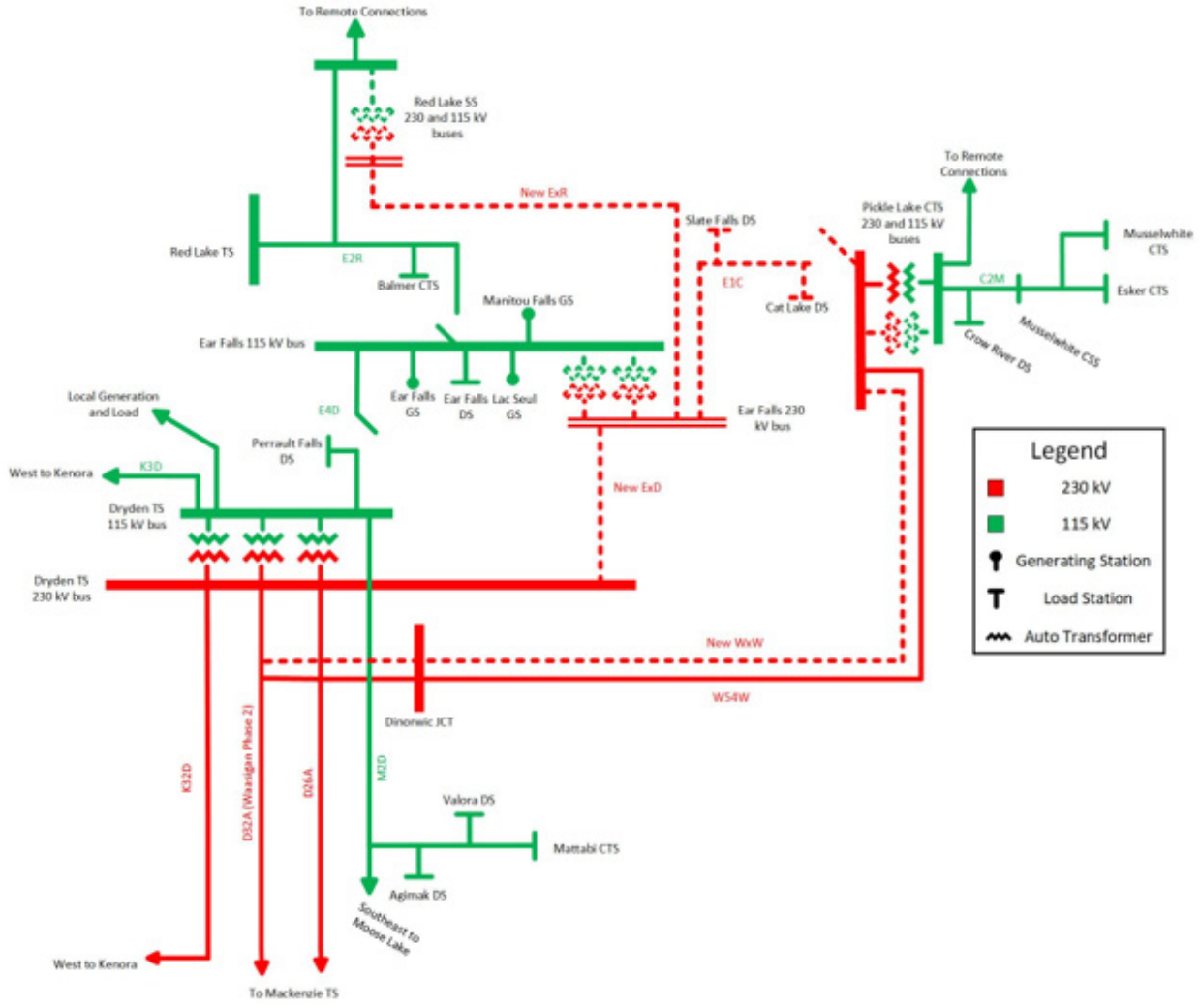
This option includes:

- 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:

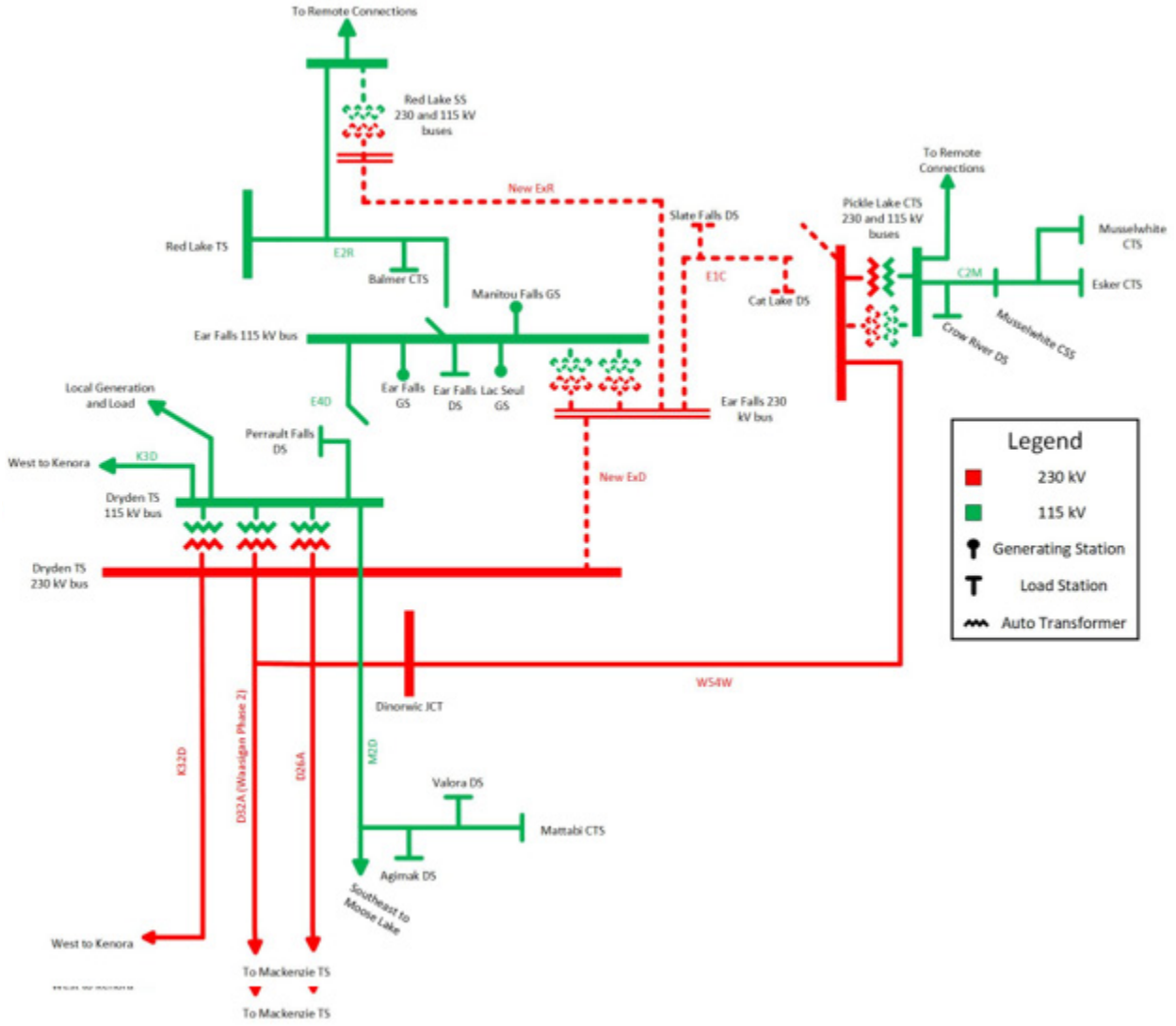
- A new 230 kV transmission line from Dryden to Ear Falls (100 km)
- A new 230 kV transmission line from Ear Falls to Red Lake parallel to E2R (62 km)
- A new 230 kV transmission line from Ear Falls to Pickle Lake (260 km)

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:

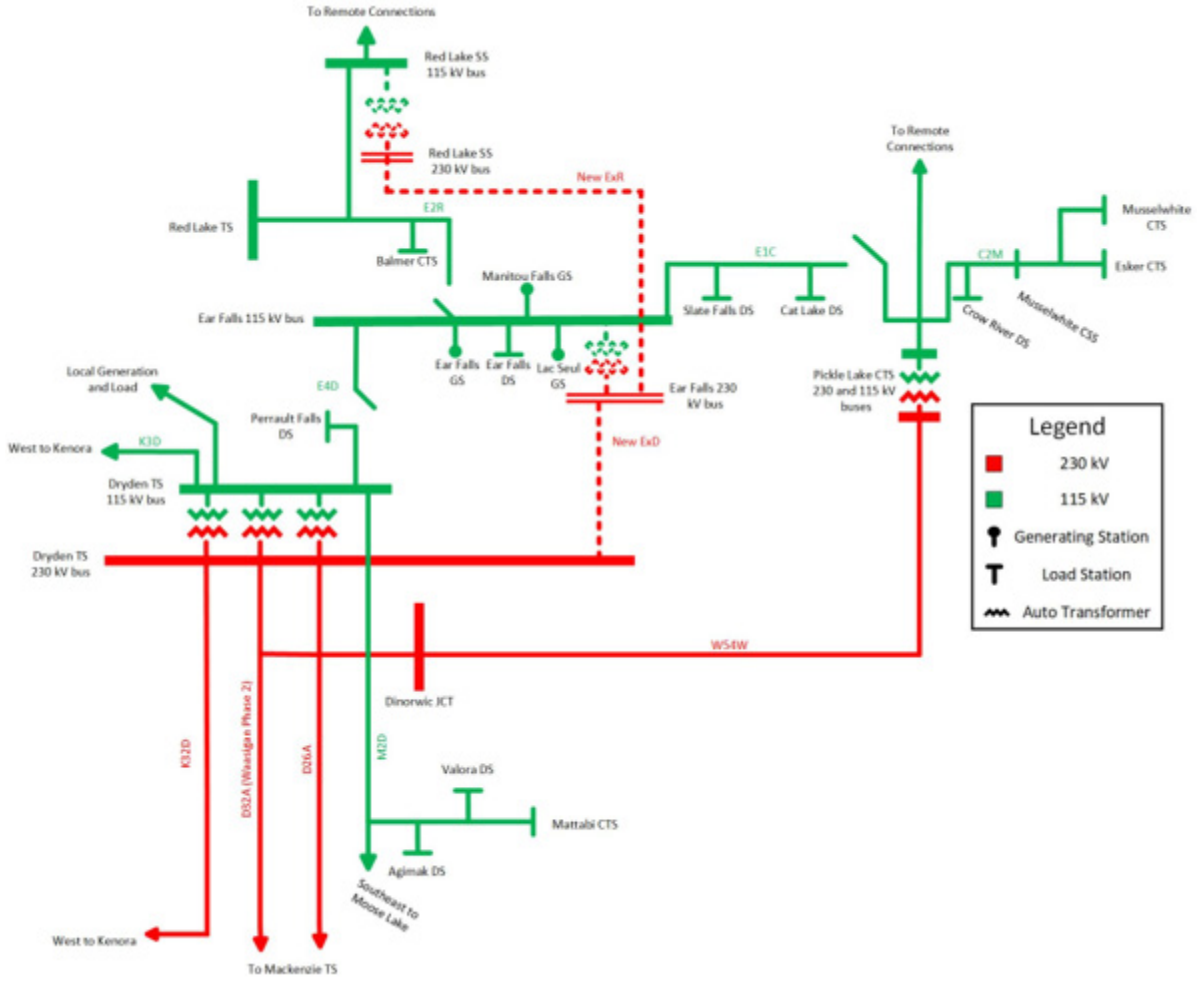
- A new 230 kV transmission line from Dryden to Ear Falls (100 km long)
- A new 230 kV transmission line from Ear Falls to Red Lake (62 km long)

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

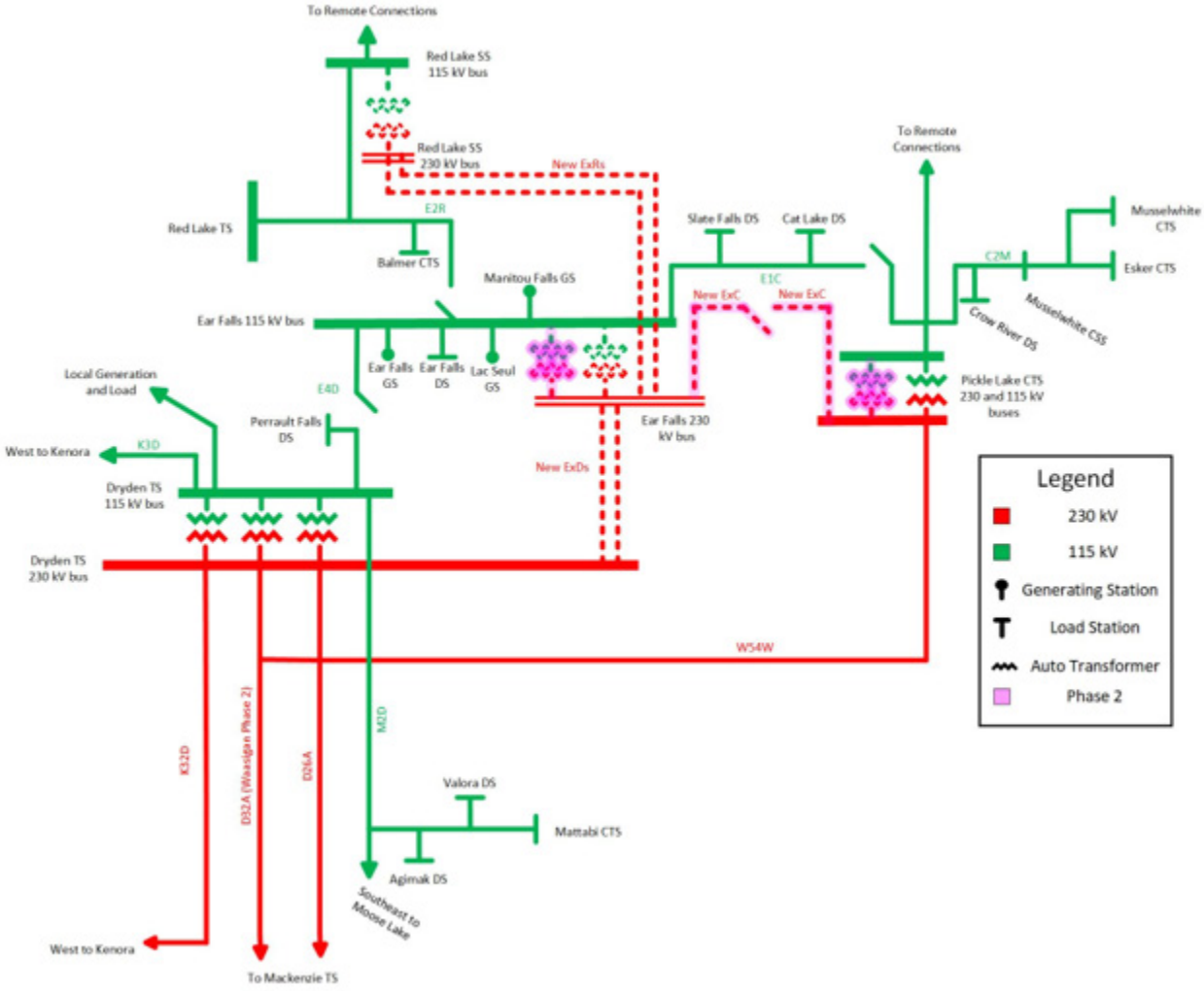
To enhance reliability and resiliency, a variation of Option 3 was studied that involved an upgraded double-circuit 230 kV line Dryden to Red Lake and reinforced supply to Pickle Lake. The following transmission upgrades summarize the scope of work needed for this option:

- 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

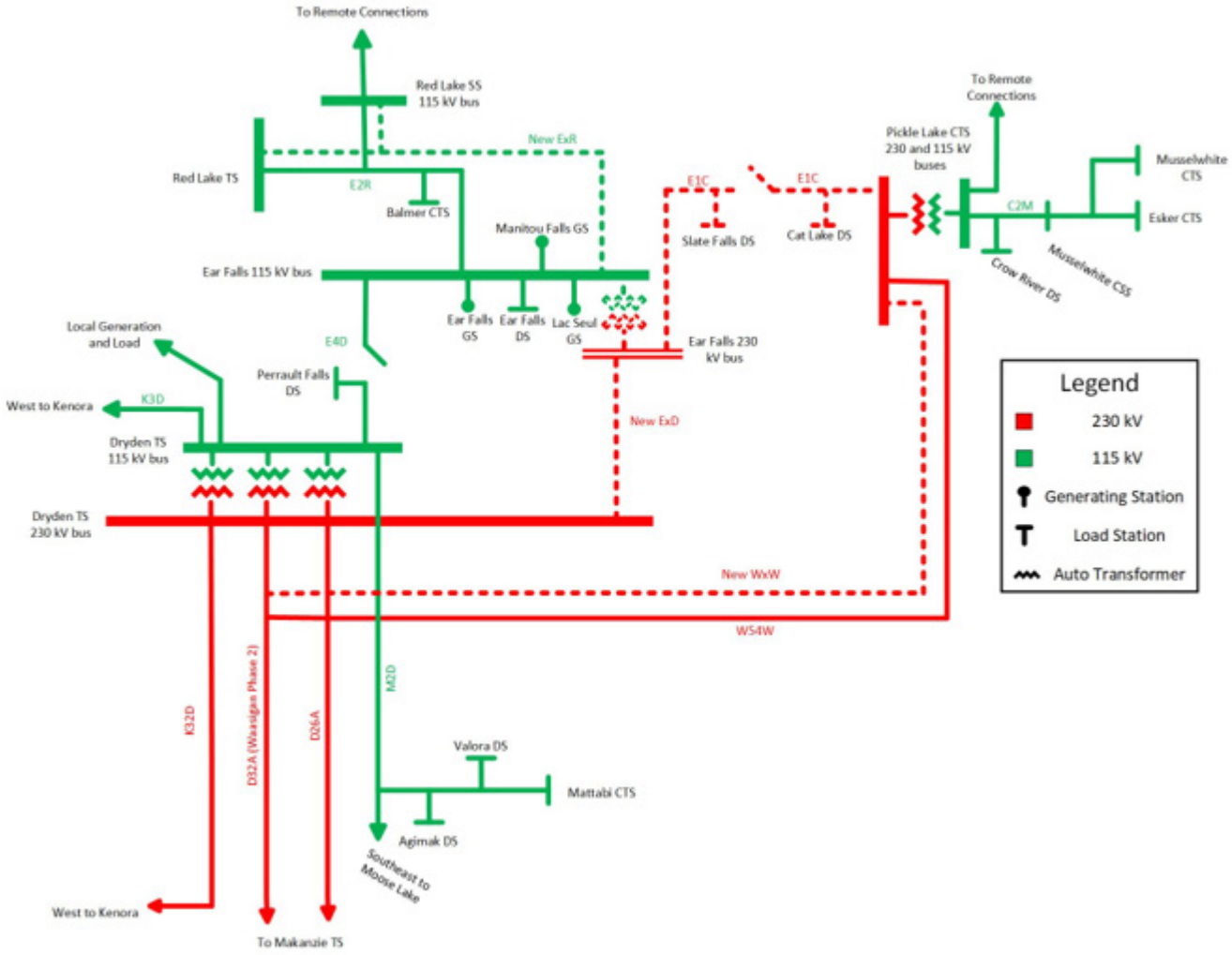


Figure B.2 | Option 2

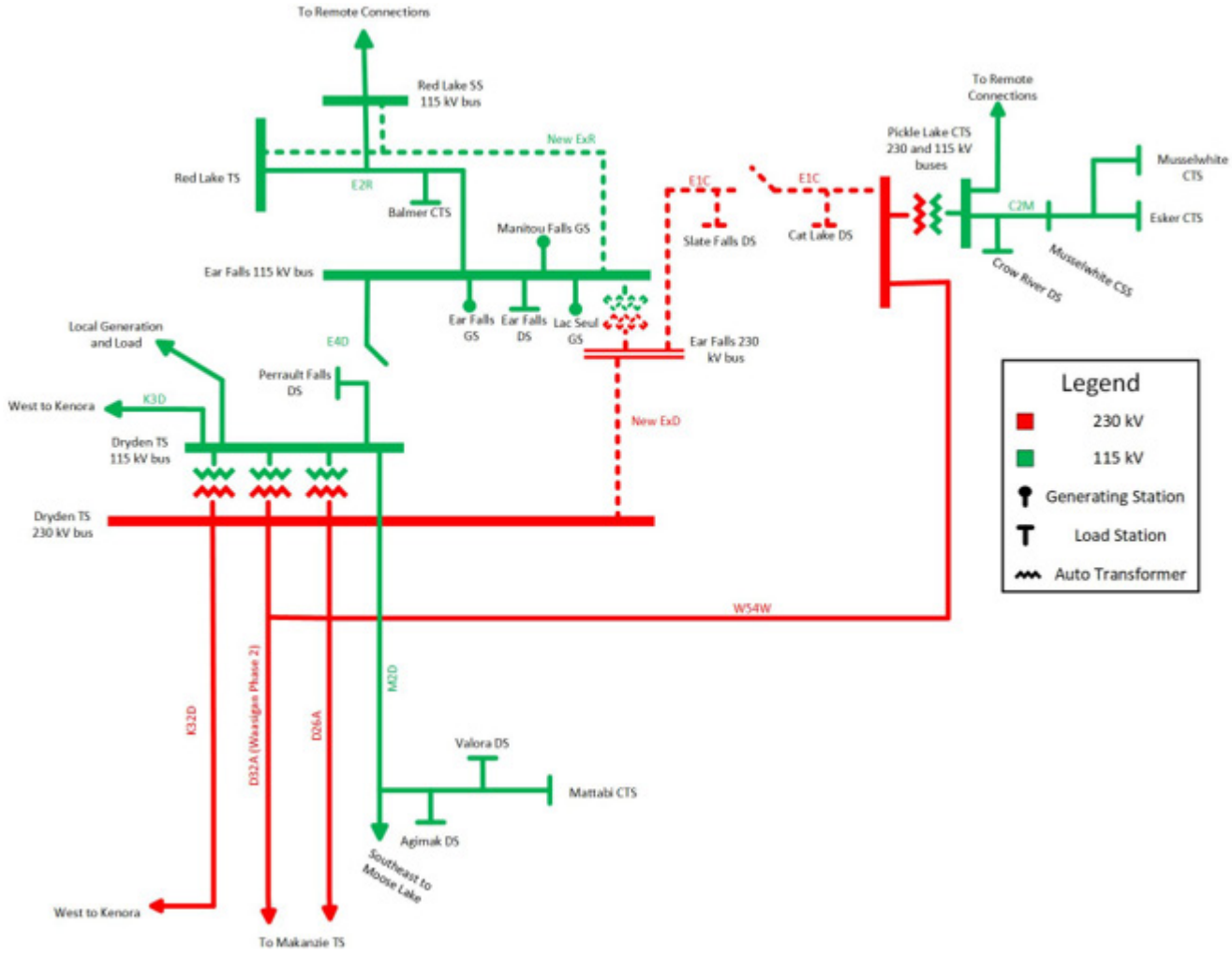
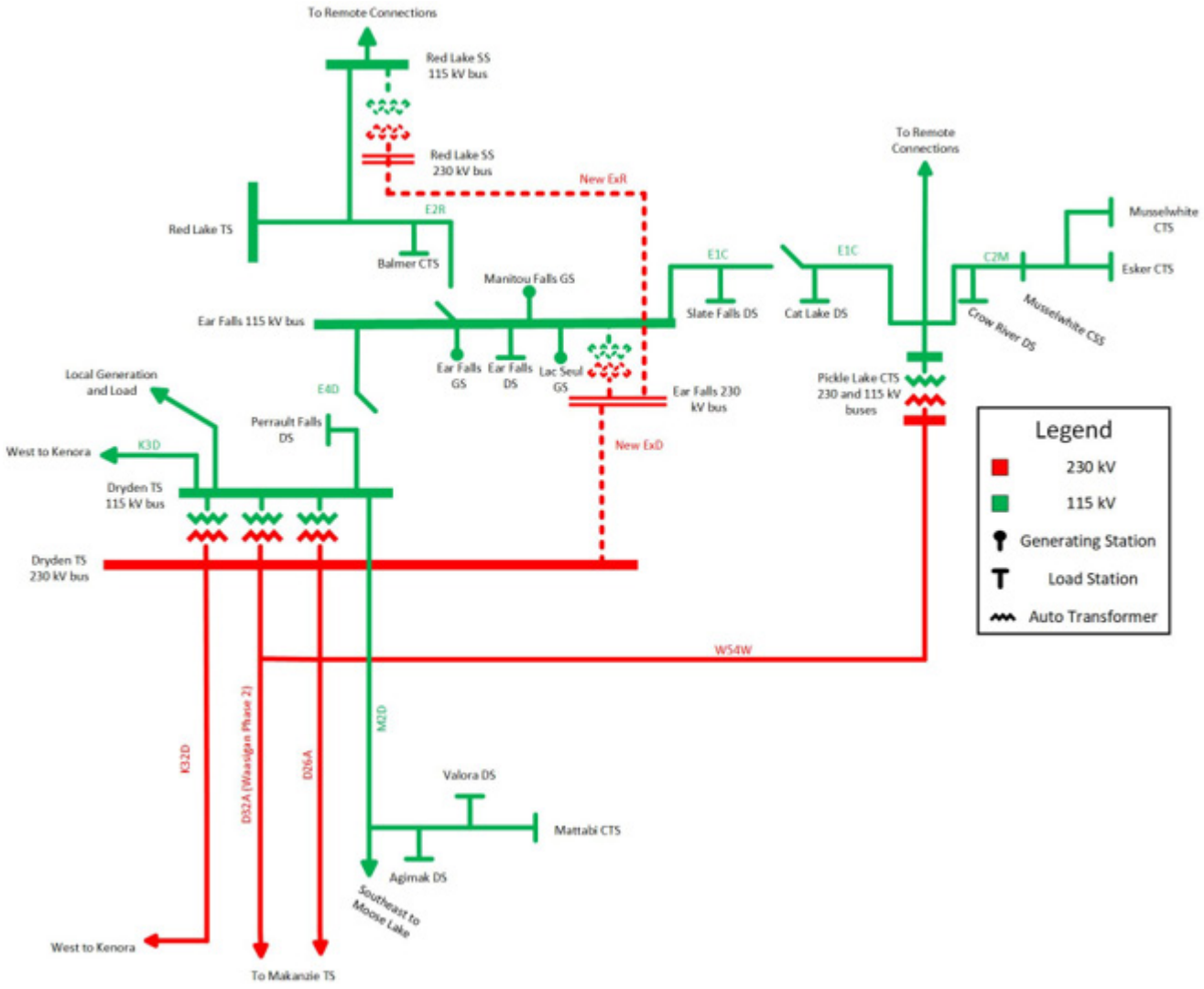


Figure B.3 | Option 3



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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Northwest Ontario Region Scoping Assessment Outcome Report

September 19, 2025

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Introduction

To keep pace with the rapid growth and economic development in Northwest Ontario, the IESO and the rest of the Northwest Region Technical Working Group is implementing a streamlined regional planning process. Specifically, the Scoping Assessment stage, which has traditionally taken several months to complete, will now be conducted in an accelerated manner, enabling the IESO to move directly into the next phase of planning. This approach reflects feedback received through stakeholder engagement and aligns with government priorities, particularly around economic development and critical mineral mining.

Engagement continues to remain central to the IESO's planning process. We are committed to working collaboratively with Indigenous communities, municipalities, developers, and consumers, each bringing unique perspectives and expertise to shaping Ontario's energy future.

The process will be initiated with the release of this Scoping Assessment Outcome Report, which concludes that a single Integrated Regional Resource Plan (IRRP) covering the entire Northwest region will be undertaken, commencing on September 22, 2025. This decision reflects the scale, magnitude, and timing of electricity needs identified by the transmitter and other members of the regional planning technical working group.

Strategic Context and Rationale

The Northwest region is experiencing robust and urgent electricity needs, driven by:

- Mining sector growth, particularly in the Red Lake and North of Dryden areas.
- Connection requests across the region, with notable activity in the Thunder Bay area.
- Provincial supply needs, as Northern Ontario plays a growing role in meeting Ontario's electricity demand.

In response, the IESO initiated an urgent IRRP Addendum in Q3 2024 focused on the North of Dryden area which resulted in significant transmission reinforcement into the Ear Falls and Red Lake areas to support mining, economic development and community growth. The expedited transition to an IRRP for the Northwest is a continuation of this proactive planning approach, enabling faster response to emerging needs and aligning with stakeholder expectations and government objectives.

Commitment to Engagement

Engagement remains central to the IESO's planning process. We are committed to working collaboratively with Indigenous communities, municipalities, developers, and consumers, each bringing unique perspectives and expertise to shaping Ontario's energy future.

The IRRP process will continue to include:

- Webinars and targeted meetings
- Broad communications
- Ongoing opportunities for feedback and dialogue

The IESO remains committed to reconciliation and to building respectful, trust-based relationships with Indigenous communities, guided by our Indigenous Engagement Framework. Committed to

ongoing, effective dialogue with Indigenous communities will help shape long-term planning across Ontario. To raise awareness about the regional planning cycle in Northwest Ontario and provide opportunities for input, the IESO will notify and invite 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 engagement activities.

- 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
- Brunswick House First Nation
- Cat Lake
- Constance Lake
- Couchiching First Nation
- Deer Lake
- Eabametoong
- Eagle Lake
- Fort Severn
- Fort William First Nation
- 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
- Mitaanjigamiing First Nation
- Muskrat Dam Lake
- Naicatchewenin First Nation
- 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
- Red Rock Indian Band
- Sachigo Lake
- Sandy Lake
- Seine River First Nation
- Shoal Lake No. 40
- Slate Falls
- Wabaseemoong
- Wabauskang
- Wabigoon Lake
- Wapekeka
- Washagamis Bay (Obashkaandagaang)
- Wawakapewin
- Webequie
- Weenusk
- Whitesand
- Whitewater Lake
- Wunnumin Lake
- Shoal Lake No. 40
- Slate Falls

  The Tribal Councils and Provincial Territorial Organization (PTO) invited to participate in engagement activities are:
- 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 Métis communities invited to participate in engagement activities are:

- Métis Nation of Ontario
- Red Sky Independent Métis Nation

Overview of Region and Background

The Northwest region includes the districts of Kenora, Rainy River, and Thunder Bay, bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. Planning in this region presents unique challenges due to its vast geography and resource-based industrial demand, which is sensitive to commodity prices and financing conditions.

Several recent and ongoing transmission reinforcement projects help improve supply capacity and reliability in the region:

- East-West Tie Reinforcement – Completed and in service
- Wataynikaneyap Transmission Project – Completed and in service
- Waasigan Transmission Line Project
- Phase 1: Under construction, in-service expected October 2026
    - Phase 2: Under construction, in-service expected December 2027
- Dryden-Ear Falls-Red Lake Transmission Plan – in-service date to be confirmed (2031-2033)
- Pickle Lake SS Reactor – in-service date O4 2026

Scoping Assessment Outcome Report Details

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

This is the third cycle of regional planning for the Northwest Ontario region, and it was initiated in summer 2025. The Needs Assessment (NA) is the first step in the regional planning process and was carried out by the Study Team led by Hydro One Networks Inc. (Hydro One). The Needs Assessment[1] was finalized on September 3, 2025. While it did not include a formal identification of specific needs, it highlighted a range of clear and emerging drivers that point to the need for further regional coordination. These include strong stakeholder and government interest in economic development particularly in the mining sector, as well as a high volume of load connection requests and inquiries. Together, these factors underscore the importance of moving the region into a comprehensive Integrated Regional Resource Plan (IRRP). The findings from the Needs Assessment served as an input to this Scoping Assessment Outcome Report.

[1] 2025 Northwest Ontario Needs Assessment, Hydro One https://www.hydroone.com/about/corporate-information/regional-plans/north-west-ontario

As part of the Scoping Assessment, the Study Team reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach to address them. The planning approaches considered include:

- **An Integrated Regional Resource Plan (IRRP)** led by the Independent Electricity System Operator (IESO) – through which a greater range of options, including non-wires alternatives, are to be considered and/or closer coordination with communities and stakeholders is required;
- **A Regional Infrastructure Plan (RIP)** led by the transmitter – which considers more straight-forward wires only option with limited engagement; or
- **A local plan (LP)** undertaken by the transmitter and affected local distribution company (LDC) – for which no further regional coordination is required.

Conclusion

This Scoping Assessment concludes that a single IRRP covering the entire Northwest Ontario region will be undertaken, with work commencing on September 22, 2025. The IRRP is expected to be completed within an 18-month timeframe, enabling timely identification and resolution of electricity needs across the region. As technical studies and engagement progress, additional needs may be identified and incorporated. The expedited planning approach enables the IESO to respond more quickly to regional and provincial electricity needs, supporting economic development and aligning with stakeholder and government priorities.

Appendix 1 – Geographic Map of Northwest Ontario Region

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BOARD STAFF – 6

Reference: Exhibit B-1-4 / page 4

Preamble: WPLP states, “The $500k cost forecast for 2025 relates to construction close out costs from final ROW inspections, which were delayed into 2025.”

Question(s):

a) Please explain the cause of the delay of ROW inspections.

b) Please explain how the $500k cost was recorded in the Fixed Asset Continuity Schedule for 2025 (and how it was adjusted for 2024).

Response:

a) ROW inspections were delayed due to contractor delays in completing restoration activities in the project footprint.

b) The $500K is recorded as a rate base addition to Overhead Conductor costs in 2025. This would not have been recorded as an addition to Overhead Conductor in 2024 actuals and therefore is not included in opening balance for 2025 in the Fixed Asset Continuity.

BOARD STAFF – 7

Reference: Exhibit B-1-4 / Table 1
Exhibit B-1-4 / Table 2

Preamble: Reference 1 sets out the transmission project capital expenditures by year. Reference 2 sets out the transmission project capital expenditures by category. Reference 1 shows two versions of the capital expenditures: the "Actual/Forecast" and "2025 Rate Application". Reference 2 also shows two versions of the capital expenditures: the "Updated Forecast" and "2025 Rate Application".

Question(s):

a) Footnote 4 on page 4 of Exhibit B-1-4 notes that the "Updated Forecast" in Table 2 is as at May 2024. Please confirm whether the "as at" date of the Updated Forecast of Table 2 should be May 2024 or May 2025 (and make any corresponding corrections to Table 2 if necessary). If the "as at" date is May 2024, please update Table 2 with May 2025 Updated Forecast data.

b) Using data in Table 1, please calculate the sum of each column and complete the table below. Please reconcile the totals in the following table with total values in Table 2, and provide explanations for any discrepancies.

Year	Transmission Project Capital Expenditures ($000s)	
	Actual/Forecast	2025 Rate Application
Total: Pre-2021 through 2025		

Response:

a) Confirmed. Footnote 4 should say "May 2025".

b) Please see table below that reconciles Table 1 to Table 2 of Exhibit B-1-4. Please note that an error was identified on Table 2 in the filed application, affecting only the amount indicated for Total Capital Costs in the Updated Forecast column. An updated Table 2 is provided below with Total Capital Cost amount corrected. The reconciliation table shows the balance in Table 1 equals balance in Table 2, less capitalized interest, consistent with how figures have been presented in WPLP's prior rate applications.

Year	**Transmission Project Capital Expenditures ($000s)**	
	Actual/Forecast	**2025 Rate Application**
Total: Pre-2021 through 2025	1,736,638	1,740,367
Balances from Updated Table 2	1,829,432	1,833,186
Variance (Represents Capitalized interest shown in Table 2)	-92,794	-92,819

Updated Table 2 of Exhibit B-1-4

(Costs in $000's)	Updated Forecast[1]	2025 Rate Application	Variance	
			$	%
EPC Costs				
Transmission Line Facilities - Line to Pickle Lake	215,166	215,166	0	0%
Transmission Line Facilities - Remote Connection Lines	911,938	911,938	0	0%
Station Facilities - Line to Pickle Lake	38,472	38,472	0	0%
Station Facilities - Remote Connection Lines	304,364	304,364	0	0%
Non-EPC Capital Costs				
EPC Excluded (e.g. Insurance, LIDAR, Stumpage)	8,913	10,271	-1,359	-13%
Engineering, Design, Project/Construction Management & Procurement	104,517	106,751	-2,234	-2%
Environmental Assessments, Routing, Permitting, Regulatory & Legal	27,236	27,275	-38	0%
Land Rights	10,844	10,918	-73	-1%
Engagement, Stakeholder Consultation, Participation and Training	42,773	43,433	-661	-2%
Contingency	0	0	0	0%
Costs Included in EB-2018-0190, Pre-AFUDC	***1,664,223***	***1,668,588***	***-4,365***	***0%***
Capitalized Interest	92,794	92,819	-25	0%
Total Costs Included in EB-2018-0190	***1,757,017***	***1,761,407***	***-4,390***	***0%***
Other Infrastructure	1,315	680	636	94%

[1] As at May 2025, with incremental COVID costs reported as separate cost category.

COVID-19 Costs	71,100	71,100	0	0%
Total Capital Costs[2]	**1,829,432**	**1,833,186**	**-3,755**	**0%**

[2] These costs do not include any amounts that may be recorded in the proposed EPC COVID-Related Costs Deferral Account.

BOARD STAFF – 8

Reference: Exhibit B-1-4 / Table 2
Exhibit B-1-4 / page 5

Preamble: Reference 1 sets out the Transmission Project capital costs, including the variance between the "Updated Forecast" (dated in footnote 4 as May 2024) and those included in the 2025 Rate Application. Reference 1 shows that, before adjustments for Other Infrastructure and COVID-19 costs, the capital costs in the Updated Forecast are $4.39 million lower than those in the 2025 Rate Application.

Reference 2 contains a description of the drivers of the variances between the 2025 Rate Application and the Updated Forecast. Summing the value of the variances described at Reference 2 results in $4.8 million, which is $0.41 million greater than the value presented at Reference 1.

Question(s):

a) Please provide an explanation and detailed breakdown of the variance in every line item at Reference 1.

b) Please reconcile the difference between the variances in line items at Reference 1 and the descriptions of variances at Reference 2.

Response:

a) Please see table below with references to detailed breakdown and explanations on variances for each line in Table 2, as updated in response to Board Staff 7 (b).

(Costs in $000's)	Updated Forecast[1]	2025 Rate Application	Variance		REF
			$	%	
EPC Costs					
Transmission Line Facilities - Line to Pickle Lake	215,166	215,166	0	0%	
Transmission Line Facilities - Remote Connection Lines	911,938	911,938	0	0%	
Station Facilities - Line to Pickle Lake	38,472	38,472	0	0%	

[1] As at May 2025, with incremental COVID costs reported as separate cost category.

Station Facilities - Remote Connection Lines	304,364	304,364	0	0%	
Non-EPC Capital Costs					
EPC Excluded (e.g. Insurance, LIDAR, Stumpage)	8,913	10,271	-1,359	-13%	A
Engineering, Design, Project/Construction Management & Procurement	104,517	106,751	-2,234	-2%	B
Environmental Assessments, Routing, Permitting, Regulatory & Legal	27,236	27,275	-38	0%	C
Land Rights	10,844	10,918	-73	-1%	D
Engagement, Stakeholder Consultation, Participation and Training	42,773	43,433	-661	-2%	E
Contingency	0	0	0	0%	
Costs Included in EB-2018-0190, Pre-AFUDC	***1,664,223***	***1,668,588***	***-4,365***	***0%***	
Capitalized Interest	92,794	92,819	-25	0%	F
Total Costs Included in EB-2018-0190	***1,757,017***	***1,761,407***	***-4,390***	***0%***	
Other Infrastructure	1,315	680	636	94%	G
COVID-19 Costs	71,100	71,100	0	0%	
Total Capital Costs[2]	**1,829,432**	**1,833,186**	**-3,755**	**0%**	

[A] LIDAR scope was not completed as part of the capital project, costs will be covered through operating costs as required.

[B] Savings of approximately $1.8 million based on Owner Engineer costs, remaining savings ($0.4 million) a result of other Project Support services like independent engineer and departmental cost savings.

[C] Minor savings in environmental GIS service requirements.

[D] Minor savings related to legal/consultant services.

[E] Savings on community engagement and training costs given minimal construction activity in 2024.

[2] These costs do not include any amounts that may be recorded in the proposed EPC COVID-Related Costs Deferral Account.

[F] Savings based on actual incurred interest rates at end of project.

[G] Additional capital costs related to other infrastructure in 2024, including the purchase of an inventory storage building in the Pickle Lake storage yard for $0.4 million and operational technology. See response to Board Staff IR 11(a) for additional information on General Plant variances.

b) WPLP clarifies that the remaining savings of $1.1 million identified at Reference 2 should be reduced to $0.6 million as it incorrectly did not account for additional ROW inspection costs ($0.5 million) to be incurred in 2025 (see response to Board Staff 7(b)). This correction changes the balance identified in Table 2 of Exhibit B-1-4 from $4.8 million to $4.3 million. The remaining variance is due to rounding. WPLP confirms that no other changes to the evidence are required as a result of this correction.

BOARD STAFF – 9

Reference: Exhibit B-1-4 / page 6

Preamble: The footnote of the reference states:

> …at the time of filing there are ongoing wildfires within the region through which WPLP's Transmission System traverses. At the time of filing, the extent of damage to WPLP's facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

Question(s):

a) Please provide an update on the extent of damage to WPLP's facilities related to the wildfires described at the reference.

b) Please describe WPLP's approach to assessing the damage to its facilities caused by wildfires or other natural disasters.

c) Please describe any measures that have been or could be taken by WPLP to reduce the risk of damage to its facilities by wildfires.

Response:

a) In total, 644 structures were within the MNRF fire boundaries. Of these, 316 were wood pole structures and 328 were steel lattice structures. 9 wood poles had damage from the fire, 5 of which were serious enough that they required immediate replacement and 4 of which will be considered for future replacement. WPLP has not amended the application as the pole replacements are not considered material to revenue requirement and WPLP will address the additional capital costs in its next rate application. As it relates to steel lattice towers, the only notable damages were burned off guy guards. Given that the costs of replacing the burned off guy guards will not be material, WPLP expects to replace them but is not amending this application to reflect those costs.

b) During an outage, the Wataynikaneyap Operations team works with Hydro One Networks though our operating agreement, as well as with Hydro One Remotes (for notification and potential startup of community wide backup) and organizations such as MNRF (for fire events) and Emergency Management Ontario as well as our emergency response contractors. In addition, WPLP provides regular communications with First Nations.

During an event, a Forward Command Post is set up to facilitate communication and collaborative restoration efforts. Using remote tools, Wataynikaneyap staff obtain fault

records to determine the type and location of a fault. If a dispatch is required, Wataynikaneyap leverages a combination of internal and external (emergency response contractor) staff along with any other support contractors as required.

If an outage is caused by a wildfire or other natural disaster, an aerial and/or ground inspection is performed when safe to do so. Considerations include air space over an active fire and ongoing weather conditions. When safe and MNR has lifted fire restrictions, an aerial and or ground inspection takes place which helps determine whether more detailed testing may be required (insulators for contaminants or steel for structural strength).

c) The items below are a list of measures WPLP has taken or is considering to reduce the risk of damage to facilities by wildfires:

   a. Selection of steel towers during EPC RFP process[1]

   b. GIS-based situational awareness tools have been implemented that overlay WPLP's assets with Ontario fire risk and fire perimeter data as well as a variety of third-party data related to wildfire risk, wildfire activity and weather conditions

   c. GIS data provided to Ministry of Energy and Mines for the purpose of coordinating critical infrastructure protection (primarily in coordination with MNRF during wildfire season)

   d. Established direct lines of communication with MNRF Sector Response Officers and Incident Commanders to coordinate asset protection for fires in proximity to WPLP transmission assets.

   e. In the process of initiating a project to develop procurement and construction standards to allow one-for-one replacement of wood poles with direct-embedded steel monopoles.

   f. Wood pole replacement program uses composite which is more resistant to wildfires.

   g. Consideration is being given to the installation of pole wraps on wood poles.

   h. Working with First Nations on emergency management plans.

[1] This selection was for the 230KV line segments and 115kV line segments. This does not include the PQ line segment that was completed as part of the Pikangikum Project in 2018.

BOARD STAFF – 10

Reference: Exhibit B-1-4 / pages 10-11

Preamble: On page 10 at the reference, WPLP states "a subset of poles are damaged each year by the feeding and nesting activity of woodpeckers." On page 11, WPLP states:

> WPLP is currently using fiber-reinforced polymer poles for replacements due to minimal difference in total replacement cost, advantages for transportation and assembly in remote areas and resistance to repeated woodpecker damage as well as other forms of decay…WPLP's estimated costs for this program are informed by historical costs for similar pole replacements.

Question(s):

a. Please state the number of poles that have been replaced each year since 2021.
b. Please provide any data or analysis produced or used by WPLP to forecast the number of poles required for replacement each year.
c. What measures does WPLP take to either reduce the likelihood of damage to poles or extend the life of poles that have been damaged? What measures could WPLP take to either reduce the likelihood of damage to poles or extend the life of poles that have been damaged?
d. Please provide an estimate of the cost, on a per pole basis, of replacing each of the four damaged poles with wood, steel, or fiber-reinforced polymer poles. Please provide additional detail on any other factors (including ease of transportation and durability) that inform WPLP's decision between these three alternatives when considering a pole replacement.
e. Please provide the "historical costs for similar pole replacements" that form the basis of WPLP's estimated costs for the replacement of the wood poles in this application. Please explain any differences between the scope or costs of the historical pole replacements and the proposed replacements.

Response:

a) Please see table below providing the number of poles replaced each year since 2021.

Year	Poles Replaced
2021	2

2022	5
2023	3
2024	2

b) The number of pole replacements is based on inspections from the previous year. Between the years of 2019 and 2022, all poles were inspected yearly. This has shifted to approximately 20% of the lines each year, plus the known poles with moderate to severe woodpecker damage.

During inspections, if a pole is noted to have moderate to severe woodpecker damage, the powerline technicians note the location of the hole, then climb the pole and measure the hole size and depth. All poles with moderate to severe damage are then assigned a criticality ranking based on number of holes as well as location, size and depth.

Any poles deemed to be in critical condition (could affect reliability) are generally changed in September, ahead of the winter where poles would see increased loading due to seasonal weather.

c) In 2021, poles with extensive woodpecker damage were replaced, and poles with moderate damage were patched using wood dowels and adhesive.

During 2022 inspections of the line, it was noted that the poles that were changed or repaired in 2021, experienced additional woodpecker damage, including evidence that a woodpecker had damaged the adhesive.

As the same poles seemed to be targeted, the approach since 2022 and has been to replace the damaged wood poles with composite poles. In multiple cases, wood poles that were patched, or replaced with another wood pole, have needed to be replaced with a composite pole.

d) Below is a cost estimate comparison for replacement of wood poles like for like, with composite, prepared on the basis of replacing four poles and with the replacement cost per pole indicated in the last column. Steel hasn't been included in the comparison as WPLP is in the early stages of evaluating the design and installation requirements for steel compared to wood or composite poles. Composite poles were selected as they provide greater woodpecker and fire resistance.

Pole Material	Mob & Demob	Pole Replacement (Labour and Equipment)	Crew Per Diem	Pole Costs	Shipping	Foundation Costs	Total Cost	Cost Per Pole
Wood	266,305	354,219	11,542	36,000	5,000	100,000	773,066	193,266
Composite	266,305	354,219	11,542	65,416	5,000	100,000	802,482	200,620

Please see assumptions used for cost estimate below:

i) As the system is a radial feed, the pole replacements are completed on 1 day of the year, typically during a Hydro One scheduled outage to minimize customer impacts.

ii) Due to long line segments, critical poles to change could be too far of a distance for a crew to complete more than 1 pole during the scheduled outage. This requires additional crews and equipment to complete the work.

iii) WPLP pole lines are located in areas where rock is prevalent, so a replacement structure may require a rock foundation for support. These are very costly compared to direct bury.

iv) Pole replacement may not be in an area accessible by road and may require specialized equipment to complete (off road equipment, helicopters etc.)

e) See table below that provides the historical costs for pole replacements.

Year	**Poles Replaced**	**Total Cost**	**Cost Per Pole**	**Notes**
2021	2	$ 160,650	$ 80,325	Replaced wood with new wood poles
2022	5	$ 557,644	$ 111,528	Replaced with composite
2023	3	$ 406,635	$ 135,545	Replaced with composite
2024	2	$ 326,453	$ 163,227	Replaced with composite

As seen in the table above, WPLP has been able to complete pole replacements for under 200k per pole. Please see notes below that highlight reasoning and efficiencies WPLP has explored.

i) Strategically replacing pole close together – WPLP has selected poles close together replace, which has reduced the number of crews needed to complete the work during the yearly outage.

ii) Scheduling Pole Replacements in conjunction with Inspections– WPLP has been able to reduce mobilization costs of crews through work scheduling, however, this is dependent on the availability of the contractor and may not always be possible.

iii) Pole replacements in road accessible areas – Pole replacements have all taken place along line PQ, which is road accessible. Approximately 50% of the wood poles on WPLP's system are not accessible year-round by road and will require the use of specialized equipment to replace.

BOARD STAFF – 11

Reference: Exhibit C-3-1 / page 2 / Table 1

Preamble: As summarized in the table below, Table 1 of Exhibit C-3-1 indicates that there are variances between the "2025 Approved" and "2025 Forecast" year-end gross asset values in the accounts listed below.

OEB Account	**Variance ($000's)**
1908-Buildings and Fixtures	377
1910-Leasehold Improvement	(21)
1920-Computer Hardware	271
1940-Tools, Shop & Garage Equipment	(1)
1945-Measurement & Testing Equipment	9
1995-Contributions & Grants	34
Total	669

Question(s):

a) Please provide explanation for each of the above variances.

Response:

a) Please see the following table which provides explanations for variance in general plant assets. Each variance is below WPLP's materiality threshold in this Application.

OEB Account	**Variance ($000's)**	**Explanations**
1908-Buildings and Fixtures	377	To protect inventory stored in Pickle Lake area WPLP procured a storage structure to protect inventory that was previously stored by its EPC contractor from the elements.
1910-Leasehold Improvement	-21	Savings on fencing for leased yard in Pickle Lake.
1920-Computer Hardware	271	Additional operational technology hardware at substations across the WPLP transmission system which include sensors for OT network monitoring at each substation and redundancy for secure remote access to substations.
1940-Tools, Shop & Garage Equipment	-1	Purchase of lift equipment for 3 remote substations. Variance is rounding.
1945-Measurement & Testing Equipment	9	Purchase of a testing bench to support testing, maintenance and patching of critical OT equipment.

1995-Contributions & Grants	34	Write-off of poles replaced on the PQ line as these were funded through the Pikangikum project.
Total	669	

BOARD STAFF – 12

Reference: Exhibit D-1-1 / page 3
EB-2022-0149 / Exhibit F-1-1 / Appendix A

Preamble: In its 2023 revenue requirement application, WPLP filed a benchmarking study that compared WPLP's OM&A expense levels on a per line kilometer and a per station basis relative to Canadian transmitters.

In the application, WPLP stated they filed a performance report in April 2025, which included OM&A cost per kilometer of line and OM&A cost per station for the year 2024.

Question(s):

a) Please project the OM&A cost per kilometer of line and OM&A cost per station for years 2023 (actual), 2024 (actual), 2025 and 2026. For 2025, please use the most recent actual OM&A data and a forecast for remaining of the year.

b) Please compare the answers from part a) with the OM&A cost per kilometer of line and OM&A cost per station from the benchmarking study and explain any differences greater than 10%.

Response:

a) Please see following table ($000s) which provides OM&A costs per kilometer of line and OM&A cost per station for 2023-2026.

	2023 Actual	2024 Actual	2025 Forecast	2026 Forecast
OM&A Costs ($000s)	$ 14,534	$ 25,084	$ 33,572	$ 38,354
Average Transmission Line Km	977	1,638	1,741	1,741
Average OM&A Costs ($000s) per Km	$ 14.88	$ 15.31	$ 19.28	$ 22.02
Average Number of Stations	9	20	22	22
Average OM&A Costs ($000s) per Station	$ 1,543.43	$ 1,254.21	$ 1,526.00	$ 1,743.36

b) Please see the following table ($000s) which provides comparison of answers from part (a) above to the benchmarking study completed in 2023 rate application (EB-2022-0149).

	2023 Actual	2024 Actual	2025 Forecast	2026 Forecast
Average OM&A Costs ($000s) per Km	$ 14.88	$ 15.31	$ 19.28	$ 22.02
Benchmarking Study Average OM&A per Km*	$ 19.85	$ 22.30	$ 20.89	$ 23.12
Variance ($)	**$ (4.97)**	**$ (6.99)**	**$ (1.61)**	**$ (1.10)**
Variance (%)	**-25%**	**-31%**	**-8%**	**-5%**
Average OM&A Costs per Station	$ 1,543.43	$ 1,254.21	$ 1,526.00	$ 1,743.36
Benchmarking Study Average OM&A per Substation*	$ 2,057.68	$ 1,959.82	$ 1,653.56	$ 1,830.79
Variance ($)	**$ (514.24)**	**$ (705.61)**	**$ (127.56)**	**$ (87.43)**
Variance (%)	**-25%**	**-36%**	**-8%**	**-5%**

*The benchmarking report included in the 2023 rate application had OM&A costs per Km and substation adjusted to 2016 figures. For this response, WPLP has used the forecasted cost that was provided in response to OEB Staff 27(a) in the 2023 Application (EB-2022-0149).

The variances in 2023 and 2024 under both average OM&A per kilometer of transmission line and OM&A per substation are lower than the benchmarking study by more than 10%. Variances on O&M for 2023 are provided in response to OEB Staff IR 38(a) of the 2025 application (EB-2024-0176), which drives a significant portion of variance. WPLP's 2024 O&M activities had savings in O&M service providers within direct operating costs and indigenous engagement and participation relative to the values presented in the 2023 Benchmarking study.

BOARD STAFF – 13

Reference: Exhibit D-1-1 / page 4

Preamble: The application states that with respect to the semi-annual reports, WPLP notes that the April 2025 report and all future reporting is focused solely on backup power and IPA transfers until fully implemented.

Question(s):

a) Please confirm that WPLP will continue to file the semi-annual reports on backup power and IPA transfers until they are fully implemented.

Response:

a) Confirmed. WPLP will continue to file semi-annual reports on backup power and IPA transfers until fully implemented.

BOARD STAFF – 14

Reference: Exhibit D-1-1 / page 5

Preamble: Under the performance outcome of "Customer Focus", WPLP proposed to include in its initial scorecard a measure that will track WPLP's success in coordinating the use of backup power resources, where available, to mitigate the customer impact of transmission system outages when they occur. This measure is described as "Customer outage impact mitigated by backup power (% SAIDI)".

Question(s):

a) Please explain with more details how this measure is calculated. What data will be used and what is the formula?

b) Please explain why this is an appropriate measure for WPLP's success in coordinating the use of backup power to mitigate the customer impact of system outages.

Response:

a) Please refer to "Table 2 – 2024 Adjusted Reliability Performance" at page 9 of Exhibit D-2-1. Results in the first column reflect T-SAIDI values without any adjustment. Results in the second column calculate adjusted SAIDI values to exclude the portion of time during an outage when the entire load at an affected delivery point is supplied by generation on the local distribution system, which more accurately reflects the reliability experienced by the end-use customer. The formula to calculate the % reduction is:

[T-SAIDI – T-SAIDI(Adjusted)] / T-SAIDI

b) WPLP's early assessment of likely outage cause and possible duration, and informed discussion with HORCI on-call personnel to make decisions on switching to backup power is an important component of using backup power to effectively mitigate outage impacts. The % SAIDI reduction metric would provide a high-level indication of how successful these efforts have been over the course of a calendar year. Given the remoteness, access challenges and radial transmission line distance, it is important to use back up power effectively to mitigate outage.

BOARD STAFF – 15

Reference: Exhibit D-1-1 / page 6

Preamble: Under the performance category of "Safety", WPLP proposed to use the measure of "Total Recordable Incident Frequency Rate (TRIFR)" in its initial scorecard.

Question(s):

a) WPLP has reported the Recordable Injuries (number of recordable injuries per year) data as a safety measure in its annual performance reports filed with the OEB. Does WPLP consider including Recordable Injuries as a safety measure for the scorecard? If not, please explain why.

Response:

a) WPLP's rationale for not using the number of recordable injuries as an individual scorecard metric is that it is not normalized for the number of hours worked, which could raise challenges for trend analysis and target setting with a growing workforce over time. TRIFR in contrast is the more appropriate metric as it simply reflects the number of recordable injuries, normalized for the number of hours worked.

BOARD STAFF – 16

Reference: Exhibit D-1-1 / page 7

Question(s):

a) WPLP has reported the NERC Vegetation Compliance status in its annual performance report. It's noted that the NERC Vegetation Compliance status has also been used as a scorecard "Public Policy Responsiveness" measure in some other transmitters' revenue requirement applications.[1] Does WPLP consider including the NERC Vegetation Compliance status as a measure for "Public Policy Responsiveness" in the scorecard? If not, please explain why.

Response:

a) WPLP has revised its proposed scorecard to include NERC Vegetation Compliance Status. See response to Staff-17.

[1] B2M LP's 2025-2029 Revenue Requirement application (EB-2024-0116); Five Nations Energy Inc.'s 2026-2030 Revenue Requirement application (EB-2025-0129)

BOARD STAFF – 17

Reference: Exhibit D-1-1 / Attachment A - Initial Proposed Scorecard

Question(s):

a) If WPLP proposes to add any new measures to the proposed scorecard, please update the Initial Proposed Scorecard in Attachment A of Exhibit D-1-1.

b) For the three placeholders for measures in the Initial Proposed Scorecard ("Asset Health Index – Stations", "Asset Health Index – Lines", and "Capacity available for load growth in connected First Nations"), please confirm that WPLP will include detailed description and method of calculation for each measure in its first multi-year application for the 2027 test year.

c) Please indicate whether or not WPLP proposes to set 2025-2029 targets for all performance measures in the scorecard. If not, please explain why. If yes, please update the Initial Proposed Scorecard and discuss how the targets are developed.

d) Please discuss WPLP's plan for tracking and reporting the scorecard measures.

Response:

a) Please see Staff-17(a), Attachment 1, where WPLP has added the NERC Vegetation Management measure in response to Staff-16.

b) Confirmed.

c) Many of the targets for scorecard measures are typically set based on consideration of 5-year average performance and/or trends, which WPLP does not have at this time. WPLP therefore does not propose to set 2025-2029 targets for all measures. WPLP has however included a target of 0 with respect to violations of the NERC FAC-003 vegetation management standard.

d) Each of WPLP's proposed scorecard measures is calculated based on reliability, safety, asset management or financial data, which are recorded as part of WPLP's routine operations and OEB reporting requirements. WPLP plans to update and publish its scorecard annually on its website, following similar timelines to the OEB's process for the publishing of electricity distributor scorecards.

Staff-17(a), Attachment 1 – Revised Scorecard

Performance Outcomes	Performance Categories	Measures		2025	2026	2027	2028	2029	Trend	Target
Customer Focus	Service Quality	Customer outage impact mitigated by backup power (% SAIDI)								
Operational Effectiveness	Safety	Total Recordable Incident Frequency Rate (TRIFR)								
	System Reliability	T-SAIFI (Average # of interruptions per Delivery Point)								
		T-SAIDI (Average total hour interrupted per Delivery Point)								
		Average System Availability (%)								
	Asset Management	Asset Health Index - Stations **Level of detail and methodology to be developed for 2027 Test Year application**								
		Asset Health Index - Lines **Level of detail and methodology to be developed for 2027 Test Year application**								
	Cost Control	OM&A per kilometre of line								
		OM&A per substation								
Policy Responsiveness*	Capacity for First Nations	Capacity available for load growth in connected First Nations **Level of detail and methodology to be developed for 2027 Test Year application**								
	Vegetation Management	Violations of NERC FAC-003 (Line to Pickle Lake)								0
Financial Performance	Financial Ratios	Liquidity: Current Ration (Current Assets/Current Liabilities)								
		Leverage: Total Debt to Equity Ratio								
		Profitability: Regulatory Return on Equity	Deemed (included in rates)							
			Achieved							

BOARD STAFF – 18

Reference: Exhibit D-2-1 / pages 4-7 / Table 1

Preamble: Table 1 of Exhibit D-2-1 shows the following T-SAFI and T-SAIDI results excluding loss-of-supply and planned outages:

	2022	**2023**	**2024**
T-SAIFI	1.67	3.94	6.58
T-SAIDI (minutes)	121.3	84.1	964.8

On page 5 of Exhibit D-2-1, WPLP stated that it experienced 46 outages to transmission delivery points in 2024. Excluding outages caused by loss-of-supply and planned outages, in 2024, there were 20 outages caused by lightning, one outage cased by a tree contact, and nine outages caused by other reasons.

Question(s):

a) Please discuss the drivers for the 2024 adjusted T-SAIFI of 6.58 and T-SAIDI of 964.8 (excluding loss-of-supply and planned outages).

b) Since May 2024, the entire transmission system has been in service. Based on the above noted 2024 T-SAIFI and T-SAIDI results, has WPLP conducted any review and analysis on the system reliability performance accordingly? If so, please discuss briefly.

c) It's noted that WPLP mentioned that it has used community-wide backup generation to mitigate the outage impacts to end-use customers. From the delivery point availability perspective, considering the drivers identified in part a) of this question, are there any actions that WPLP has taken or plans to take in order to improve the reliability performance of the transmission system?

Response:

a) Please see tables below provided drivers for the 2024 T-SAIFI and T-SAIDI.

Causes code 0 (Unknown):				
SAIFI (Frequency)				0.769231
SAIDI (Duration)				430.8936
Number of outages				3
*All of these outages were investigated but the cause of these outages were unknown				

Causes code 300 (Tree Contact):				
SAIFI (Frequency)				0.769231
SAIDI (Duration)				648.4821
Number of outages				1
*This outage was caused by a tree that fell on the W54W line. Due to assistance from HONI the response time for this outage was reduced.				

Causes code 400 (Lightning):				
SAIFI (Frequency)				3.769231
SAIDI (Duration)				45.85128
Number of outages				20
*All of these outages were lightening caused.				
*4 of these outages were momentary outages that did not effect the SAIFI/SAIDI.				

Causes code 500 (Equipment Failure):				
SAIFI (Frequency)				0.769231
SAIDI (Duration)				59.11538
Number of outages				1
*This outage was caused by a failure of A-S3, a switch associated with A-R1. This issue is still being investigated but the failure is believed to be due to an issue with the motor clutch.				

Causes code 600 (Weather):				
SAIFI (Frequency)				0.5
SAIDI (Duration)				105.6542
Number of outages				3
*All three of these outages were caused by ice build up on the WDE line.				

Causes code 900 (Weather):				
SAIFI (Frequency)				0
SAIDI (Duration)				0
Number of outages				1
*This outage was a momentary outage that did not effect the SAIFI/SAIDI.				
Excluding Loss-of-Supply and Planned Outages:				
SAIFI (Frequency)				6.576923
SAIDI (Duration)				964.7683
SAIDI Adjusted for Generation Use (Duration)				502.9881
Availability				0.998097
Adjusted System Availability % (Excl LOS and Planned)				0.999008
Additional Notes				
The SAIDI adjusted for generation use highlights the importance of backup generation and the increased reliability it has for the customer.				

b) With lightning presenting the largest contribution to T-SAIFI, WPLP has implemented location-based tracking of lightning-caused outages, with two primary objectives:

i. Recording distance to fault indications from protection relays to determine if there are repetitive lightning-induced flashovers that may warrant investigation of insulators and/or testing of ground connections.

ii. Comparing the rate of lightning-caused outages (normalized per 100km of transmission line) to design criteria and industry standards.

WPLP intends to continue tracking this data and completing further analysis as multiple years of data become available. Analysis of other outage causes will be considered as warranted by future system reliability performance and regular analysis of outage cause codes.

c) With a single tree-caused outage being the largest contributor to 2024 SAIDI, WPLP has prioritized High-Risk Tree Removal in late 2024 and into 2025, with a focus on the 230 kV Line to Pickle Lake and a portion of the 115 kV system North of Pickle Lake where the ROW was cleared early during construction. WPLP has also assessed (and continues to assess and prioritize) areas where edge of ROW trees have become High-Risk Trees resulting from significant wildfire activity in the North of Red Lake area in 2025. WPLP notes that with the extent of long, radial transmission lines serving remote communities and the known challenges involved with accessing much of the transmission footprint, the provision of backup power was a critical component for end-customer reliability

identified during engagement between First Nations, Government and IESO during the development of the project. Since weather conditions and daylight limitations can cause significant delays for WPLP and HORCI accessing areas within the WPLP footprint following an unplanned outage, WPLP continues to collaborate closely with HORCI to use backup power (where available) to mitigate the impact of transmission system outages.

Please also refer to Section C of Exhibit B-1-4, where a number of projects have been identified in relation to system reliability and outage response. The importance of backup power to the success of the Project, and the unique lens through which reliability must be viewed for WPLP's transmission system, is further described at section 3.4.4 of the Decision and Order in WPLP's Leave to Construct application (EB-2018-0190).

BOARD STAFF – 19

Reference: Exhibit D-2-1 / pages 8-9
Filing Requirements For Electricity Transmission Applications - Chapter 2 Revenue Requirement Applications (Filing Requirements) / section 2.6.2

Preamble: Section 2.6.2 of the Filing Requirements states that the applicant should compare the results for its system performance to those of other systems both nationally and internationally, where available. The applicant must also document how it has addressed the performance standards for transmitters as set out in Chapter 4 of the Transmission System Code (TSC).

In its application, WPLP stated that it does not believe that transmission system reliability comparison with other utilities would be appropriate. WPLP plans to establish future transmission system reliability performance standards that are based on trending of its own system performance over multiple years, supplemented by consideration of unitized outage statistics from other sources where such data is both available and aligned with WPLP's unique circumstances. WPLP noted that this approach will require tracking and analyzing multiple years of baseline performance data for WPLP's transmission system…

Question(s):

a) In order to comply with the comparison requirement in Reference 2, did WPLP consider comparing its reliability performance results with the results of other transmission systems in remote areas of Ontario/northern Ontario (with adjustment factors or explanations of unique circumstances if necessary)? If not, please explain why this type of comparison is not considered appropriate, or cannot be provided.

b) If WPLP proposes not to compare its system performance results with other transmitters' and plans to establish its own performance standards (as stated in the second paragraph on page 8 of Exhibit D-2-1):

   i. Please provide a better (clear and more detailed) description of WPLP's proposal for establishing new performance standards.
   ii. Please also indicate what data/statistics and how many years' data/statistics will be analyzed for setting up the standards.
   iii. In which rate year's application, does WPLP expect to provide the proposed performance standards? In years before the new performance standards are established, what is WPLP's plan to satisfy the above noted filing requirement and review/evaluate its reliability performance in the rate applications?

c) In the third and fourth paragraphs on Exhibit D-2-1, WPLP discussed developing performance standards as required in section 4.5.1 of the TSC. Please clarify if the performance standards noted in part b) above are the same performance standards WPLP plans to develop as required in the TSC. If not, address each of the three questions in part b) specifically for WPLP's proposal for performance standards required in the TSC.

Response:

a) WPLP considered comparing its reliability performance results with results of other transmission systems in remote areas of Ontario/north Ontario, however, the only other transmitters operating transmission assets that include delivery points in remote areas of Northern Ontario are Hydro One Networks (HONI) and Five Nations Energy (FNEI). The size of HONI's transmission system, the scale of its operational workforce and the configuration of its transmission system is not comparable to either WPLP or FNEI, making comparison of reliability performance impractical.

In comparison to FNEI, WPLP's transmission is significantly larger in terms of line km, delivery points and number of substations. While both systems are located in remote areas of Northern Ontario, there are significant differences in terrain, weather patterns, wildfire activity and other factors influencing reliability. For context, the closest points between the WPLP transmission system and the FNEI transmission system are over 400 km apart. The use of adjustment factors to compare reliability metrics would not be feasible or appropriate given the differences in size and location between FNEI and WPLP.

WPLP notes that Five Nations Energy was also unable to benchmark its reliability performance against other transmitters in its most recent rate application.[1]

b)

i. WPLP proposes to establish delivery point performance standards in accordance with Section 4.5.1 of the TSC, which specifies the requirements for such procedures. For clarity, WPLP proposes to develop similar delivery point performance standards to those that the OEB has approved for other transmitters, with consideration of migrating away from load-based thresholds towards configuration and distance-based thresholds as discussed amongst the OEB's Reliability and Power Quality Review Transmission Subgroup.

ii. WPLP considers that 5 calendar years of data with its entire transmission system in service (i.e. 2025-2029) would be sufficient for setting initial performance

[1] EB-2025-0129, Exhibit 4, Page 7 of 12

standards, which may be subject to review at a later date when more data is available.

iii. On the assumption that WPLP's first multi-year rate application covers the five-year period of 2027-2031 and that WPLP files a subsequent application in respect of a 2032 test year, WPLP would be in a position to provide the proposed performance standards in its 2032 test year application.

c) Confirmed.

BOARD STAFF – 20

Reference: Exhibit E-1-1 / pages 2-4

Preamble: The application indicates that:

1. WPLP does not have weather-normalized historical data at this point in time and has not developed a load forecast based on weather-normalized data.

2. WPLP expects to develop a more robust load forecasting method as it acquires a suitable amount of historical consumption data, over at least two years, for the grid-connected communities.

Question(s):

a) Please indicate when WPLP expects to have weather-normalized historical data available. In which future rate year's application, does WPLP expect to file a load forecast based on weather-normalized data?

b) What are the efforts made to acquire a suitable amount of historical consumption data for the grid-connected communities?

c) What is WPLP's plan with respect to developing a more robust load forecasting method? In which future rate year's application, does WPLP expect to apply the more robust load forecasting method?

Response:

a) At the present time, WPLP is unable to determine if or when it will be able to file a load forecast based on weather-normalized data. Weather normalization necessarily relies on establishing a statistically significant correlation between historical weather data and historical electricity consumption, which may or may not be possible in WPLP's service area.

b) WPLP has worked with HORCI to acquire consumption data annually for each grid-connected community and intends to continue this process. With all communities now grid-connected[1], WPLP will be requesting further granularity in this data to establish a dataset of metered delivery point data starting with the 2025 calendar year.

c) Once several years of granular grid-connected consumption data is available for all delivery points, WPLP will be able to test the viability of both weather-normalized load

[1] With exception to Muskrat Dam, see response Board Staff 2 (a) for status update.

forecast models and normalized average use per customer models. WPLP does not anticipate being able to use a more robust load forecast model for its 2027 test year application. Assuming that application covers a 2027-2031 multi-year period, WPLP will likely be able to file a more robust load forecast model in support of its 2032 test year application.

BOARD STAFF – 21

Reference: Exhibit F-2-1 / Table 1
Exhibit F-2-1 / Attachment A – OM&A Expenses by OEB Account

Preamble: Table 1 of Exhibit F-2-1 summarizes the 2022-2026 OM&A expenses as below ($000's):

Category	**2022 Actuals**	**2023 Actuals**	**2024 Actuals**	**2025 Forecast**	**2026 Plan**	**Variance 2025 to 2026**
Operations	1,318	5,533	9,573	16,038	18,096	2,058
Maintenance	-	2,890	1,271	7,997	10,875	2,878
Administration & General	2,638	8,578	14,061	9,537	9,382	(155)
Total OM&A	3,956	14,534	25,084	33,572	38,354	4,782

Question(s):

a) For 2023 Actuals, it's noted that the sum of the amounts of Operations, Maintenance, and Administration & General does not equal the Total OM&A of $14,534k as shown in the last row of the table. (It's also noted that the Operation and Maintenance amounts do not match these two amounts in Table 1 of Exhibit F-2-1 in WPLP's last year's application.) Please check and correct the 2023 column in Table 1.

b) For 2024 Actuals, its noted that the sum of amounts of Operations, Maintenance, and Administration & General does not equal the Total OM&A of $25,084k as shown in the last row of the table. Please check and correct the 2024 column in Table 1.

c) For 2025 Forecast data, please indicate the "as at" date of this forecast and how the forecast was established. Does the forecast include any actual monthly OM&A expenses in 2025? Or does this forecast just reflect the reduced 2025 OM&A budget as agreed in the settlement proposal in WPLP's 2025 rate proceeding?

d) For 2025 Forecast, it's noted that the three amounts of Operations, Maintenance, and Administration & General do not match the sub-total amounts as listed in Reference 2 (Attachment A table). Please review and make necessary corrections.

Response:

a) Please see table below with corrected amounts shown in bold font. No further updates are required to the evidence as a result of this correction.

Category	**2022 Actuals**	**2023 Actuals**	**2024 Actuals**	**2025 Forecast**	**2026 Plan**	**Variance 2025 to 2026**
Operations	1,318	**5,239**	**9,752**	**16,725**	18,096	2,058
Maintenance	-	**717**	1,271	**7,311**	10,875	2,878
Administration & General	2,638	8,578	14,061	9,537	9,382	-155
Total OM&A	3,956	14,534	25,084	33,572	38,354	4,782

b) Please see corrected table in response to Board Staff 21 (a) above.

c) The forecast is "as at April 30, 2025," WPLP did take into consideration actual costs incurred as of April 30, 2025 and planned activity for the remainder of the 2025 bridge year when determining its forecast. Taking everything into consideration the 2025 OM&A budget forecasts remains at the agreed upon balance within the settlement proposal in WPLP's 2025 rate proceeding.

d) Please see corrected table in response to Board Staff 21 (a) above.

BOARD STAFF – 22

Reference: Exhibit F-2-1
EB-2024-0176 / WPLP's response to OEB Staff Interrogatory 29
EB-2023-0168
EB-2022-0149
EB-2021-0134

Preamble: Table 2 of Exhibit F-2-1 indicates that WPLP's 2025 total OM&A budget (as reduced per EB-2024-0176 settlement agreement) is $33,572k.

Based on evidence provided in the current application and in WPLP's response to OEB Staff Interrogatory 29 in WPLP's 2025 Revenue Requirement proceeding (EB-2024-0176), OEB staff summarized the 2022-2026 total OM&A expense information in the following table.

OM&A Expenses ($000's)					
	2022 (EB-2021-0134)	**2023 (EB-2022-0149)**	**2024 (EB-2023-0168)**	**2025 (EB-2024-0176)**	**2026 (EB-2025-0192)**
Proposed (A)	9,441	20,920	30,984	34,715	38,354
OEB-Approved	9,441	19,874	29,435	33,572	N/A
Actual (B)	3,956	14,534			N/A
% OM&A Over-estimated (C=(A-B)/B)	139%	44%			N/A

Question(s):

a) Please complete the above table (fill the empty cells) which shows the proposed, approved, actual OM&A expense, and percentage of over-estimated OM&A for 2022-2026. In the cell for "Actual 2025", please provide the sum of the most up-to-date 2025 actual (as of September 2025) and current forecast for the remaining of the year.

b) Considering the relatively high percentage of over-estimated OM&A in historical years, has WPLP taken any actions to improve the accuracy and quality of its OM&A estimate in establishing the 2026 budget? If yes, please discuss.

Response:

a) Please see table below with proposed, approved and actual OM&A expense. WPLP has provided actuals for 2025 up to August, given the September close numbers are not available.

OM&A Expenses ($000's)					
	2022 (EB-2021-0134)	**2023 (EB-2022-0149)**	**2024 (EB-2023-0168)**	**2025 (EB-2024-0176)**	**2026 (EB-2025-0192)**
Proposed (A)	9,441	20,920	30,984	34,715	38,354
OEB-Approved	9,441	19,874	29,435	33,572	N/A
Actual (B)	3,956	14,534	25,084	August Actuals: 16,711 Remaining Forecast: 16,861	N/A
% OM&A Over-estimated (C=(A-B)/B)	139%	44%	24%	3%	N/A

b) As shown in the response to Board Staff 22(a), above, the variances between approved and actual OM&A have declined significantly year-over-year. WPLP continues to review prior history to support the bottom-up budget approach as discussed in response to Board Staff IR 25(a). WPLP looks at historical spend patterns, executed contracts and requests external estimates to support the budget requirements. An example of WPLP's methodology to support estimation is provided for the vegetation management program in Board Staff 23(a). Now that WPLP's transmission project assets are fully in service and there are not contractors within the remote project footprint, WPLP expects its operating costs to be in line with forecasts.

BOARD STAFF – 23

Reference: Exhibit F-2-1 / Table 2

Preamble: Table 2 – "2026 OM&A Cost Drivers" indicates that the forestry expenses is increasing from $1.09 million in 2025 budget to $4.55 million in 2026 forecast (over 316% increase). WPLP noted that this forecast increase is related to continued ramp up of its vegetation management program.

Table 2 also indicates that the expenses in Substation and Line Routine Maintenance is increasing from $5.50 million in 2025 budget to $7.33 million in 2026 forecast.

Question(s):

a) With respect to the forestry expenses, please provide responses to the following questions:

   i. Please provide a detailed breakdown of the $4.55 million forecast for forestry expenses in 2026.

   ii. What methodology was used to estimate the $4.55 million cost for vegetation management in 2026? Please provide details on how historical brushing rates, LiDAR data, or contractor quotes have contributed to the development of this estimate?

   iii. What constitutes a "typical brushing cycle" for WPLP's transmission corridors, and what is the expected frequency of full-cycle brushing? Why is the rationale behind 50% of the brushing cycle being executed in 2026, and how was this scope determined?

   iv. What specific data is WPLP currently accumulating regarding Right-of-Way growth patterns, and how is this data being used to inform the prioritization, timing and geographic targeting of brushing activities?

b) With respect to expenses in Substation and Line Routine Maintenance, please provide responses to the following questions:

   i. Please provide a detailed breakdown of the $7.33 million allocated to routine line and substation inspection and maintenance activities. What was the actual cost for these activities in 2025 and 2024?

   ii. Please describe the pricing structure under the IMER Services Agreement that governs these maintenance activities.

iii. Given that most WPLP assets are newly constructed, why is such a high level of routine maintenance required in 2026?

Response:

a)

i. The following table provides a cost breakdown of the $4.55 million forecast in forestry expenses in 2026. Notes below the table for each program area describe how the forecasted units and the unit costs were developed for budgeting purposes in consideration of limited WPLP-specific historical costs being available for these activities.

Program	**Units**	**Unit Cost**	**Total ($000's)**
High-Risk Tree Removal	290 km	$1,750/km	$508
Brushing	864 Ha	$4162/Ha	$3,596
Substation Weeding	22 Stations 3 times per year	$600/occurrence	$40
Other			$408

ii. The methodology for the estimate has been provided for each of the program areas below:

High-Risk Tree Removal: This program addresses the need to remove trees near the edges of WPLP's ROWs that are: (1) tall enough to contact transmission assets when falling, and (2) leaning towards the right of way and/or have a high risk of failure due to declining tree health. The 2026 forecasted units assumes that this activity will be required on an approximate 6-year cycle (i.e. 1742 total line km / 6 = 290). Unit costs for this program were previously budgeted in the range of $3000-3500/km (comparable to Transmission Line Clearing unit costs reported by other Ontario transmitters on their scorecards and in their prior rate applications), but were reduced for 2026 based on WPLP's initial high-risk tree removal activity undertaken in late 2024 and early 2025.

Brushing: This program manages the regrowth of vegetation within the ROW in a manner that allows ongoing safe access to transmission assets and maintains required clearances between vegetation and transmission conductors, considering both the maximum sag of transmission line conductors and vegetation growth rates between brushing cycles. WPLP has assumed a 4-year cycle for efficient brush control without the use of herbicides[1], with a total ROW area of approximately 6912 Ha resulting in an annual requirement to perform brushing on 1728 Ha of ROW. For 2026, WPLP proposes to complete brushing on 50% of a typical annual cycle with a transition to full-cycle brushing starting in 2027. This will allow WPLP to gain field experience with actual costs, challenges and data verification in parallel with the analysis efforts described in part iv below.

Substation Weeding: This program involves the removal of weeds within the fenced substation area and the area immediately surrounding the substation, to prevent long-term growth of vegetation in substations and to preserve the effectiveness of the stone insulating layer for mitigation of step and touch potential hazards. WPLP anticipates having labourers perform this task 3 times per year, at the same time as its IMER inspections are occurring, so that qualified substation technicians can oversee the safety of the labourers performing this work.

Other: This budget category allows for consultant costs associated with data collection and analysis to support the development and refinement of vegetation management plans, cycles and work methods as well as contractor management (e.g. contracted WPLP field representatives to ensure safety, work quality and work completion) for contractors performing the High-Risk Tree Removal and Brushing Programs.

iii. See response to part ii above.

iv. Data collection and analysis were done using LiDAR and 3D imagery to determine current maintenance priorities and to identify preventative maintenance measures including workload and cycle frequency. Landcover data was mapped to the width of the cleared ROW to identify vegetation species type, current height and density, location and proximity to wires. This analysis and prioritization is ongoing and is expected to be used to refine priority areas for the High-Risk Tree Removal and Brushing Programs when executing work in 2026, as well as for refining the longer-term forecasts that will be used to support WPLP's upcoming multi-year rate application

[1] As discussed in WPLP Guiding Principles provided in Exhibit B-1-1 of the 2026 rate application.

b)

i. Please see the table below (all costs in $000's)

Program	**IMER Fixed Price**	**2024 Actual**	**2025 Forecast**	**2026 Proposed**
Substation Routine Inspections	Yes	1,410	1804	1,804
Substation Electrical/Mechanical Inspections/Testing	Yes	432	851	1,409
Substation Other	No	5	233	269
Lines Annual Aerial System Inspection	Yes	549	951	1,111
LiDAR	No	0	0[2]	1,285
Lines - Ground Inspections (6-Year Cycle)	Yes	1,229	1,182	1,218
Lines – Sample Tower Climbing Inspections	Yes	366	377	131
Wood Pole Line Additional Inspections	No	0	100	100

ii. For all items marked "Yes" in the "IMER Fixed Price" column in the response to part i. above, the IMER Services Agreement includes defined scope, frequency and fixed-price costs for each year 2022-2026.

[2] WPLP plans to incur LiDAR work in 2025 but has not adjusted 2025 forecast from that which was approved by OEB as part of 2025 rate proceeding given expected savings in 2025.

iii. WPLP does not agree with the characterization that the proposed activities represent a high level of routine maintenance. The scope and frequencies of these activities (e.g. substation visual inspections 3 times per year; annual aerial inspection of transmission lines, ground inspections on a 6-year cycle, etc.) are consistent with good utility practice and manufacturer recommendations. The costs of executing these activities may appear to be higher than other Ontario transmitters due to the remoteness and/or size of WPLP's transmission system, which results in requirements to contract helicopter providers in order to efficiently access the majority of the system. WPLP notes that performing the above activities on frequencies that are consistent with good utility practice provides important information to manage future costs. For example:

- the data obtained from repeat LiDAR flights will allow WPLP to develop efficient vegetation management cycles;
- the data obtained from routine inspections is critical to assessing asset health to refine future maintenance programs for efficiencies; and,
- the data obtained from substation electrical/mechanical inspections/testing and lines sample tower climbing inspections is critical to ensure that any major asset deficiencies and/or systemic material issues are identified and addressed within the 5-year warranty period included in WPLP's EPC contract.

BOARD STAFF – 24

Reference: Exhibit F-2-1 / pages 1-4

Preamble: The 2025 bridge year total OM&A expense shown in Table 2 of Exhibit F-2-1 are used as the base point for 2026 test year OM&A cost driver analysis in this application. WPLP stated that "A comparison to 2022-2024 actuals is not considered valuable given the smaller number of assets in service in 2022 and 2023, as well as that not all assets were in service for the entirety of each of these years and efficiencies as a result of the EPC contractor being in the field, which is no longer available in 2026."

Question(s):

a) Please provide a complete five-year OM&A forecast by replicating Table 2 for the years 2027 to 2029, if possible. If not possible, please explain what information is outstanding that prevents WPLP from providing a five-year OM&A forecast now.

Response:

a) The tables below provide a complete five-year OM&A forecast. As WPLP is continuing to gain historical information on operating the WPLP transmission system and future requirements of the new in-service assets, the 2027-2029 OM&A forecast is subject to change. In particular, WPLP notes that the initial term of its IMER agreement expires December 31, 2026, and that its vegetation management program is still being developed.

	Cost Driver Description	2025 OM&A	2026 OM&A Cost Driver ($000's)				2027 OM&A Cost Driver ($000's)			
			Operations	Maintenance	Administration	Total	Operations	Maintenance	Administration	Total
Direct Operating	Direct O&M Labour and Department Costs	3,416	1,777	1,777	0	3,555	1,813	1,813	0	3,626
	Controlling Authority (3rd Party)	2,783	2,839	0	0	2,839	2,896	0	0	2,896
	Substation and Line Routine Maintenance	5,499	7,328	0	0	7,328	8,231	0	0	8,231
	Emergency Response	2,886	0	2,936	0	2,936	0	2,990	0	2,990
	Forestry	1,094	0	4,551	0	4,551	0	8,310	0	8,310
	Environmental	2,540	2,343	0	0	2,343	2,372	0	0	2,372
	Other (Material, Fleet, Insurance)	1,032	728	201	403	1,331	743	205	411	1,358
	Sub-Total	*19,250*	*15,015*	*9,465*	*403*	*24,883*	*16,054*	*13,318*	*411*	*29,782*
Overhead Costs Allocated to OM&A	Labour and Departmental Costs	6,459	1,671	0	5,239	6,910	1,704	0	5,344	7,048
	Environmental Services	581	0	0	0	0	0	0	0	0
	Other Consultants (Allocate)	1,412	0	0	1,088	1,088	0	0	1,110	1,110
	Indigenous Engagement & Communications	3,403	1,410	1,410	0	2,820	1,438	1,438	0	2,876
	Stakeholder Engagement	-	0	0	0	0	0	0	0	0
	Indigenous Participation and Training	816	0	0	977	977	0	0	997	997
	Administrative Costs	1,652	0	0	1,676	1,676	0	0	1,710	1,710
	Sub-Total	*14,322*	*3,081*	*1,410*	*8,980*	*13,471*	*3,143*	*1,438*	*9,160*	*13,740*
Total		**33,572**	**18,096**	**10,875**	**9,383**	**38,354**	**19,197**	**14,756**	**9,570**	**43,523**

	Cost Driver Description	2028 OM&A Cost Driver ($000's)				2029 OM&A Cost Driver ($000's)			
		Operations	Maintenance	Administration	Total	Operations	Maintenance	Administration	Total
Direct Operating	Direct O&M Labour	1,849	1,849	0	3,698	1,886	1,886	0	3,772
	Controlling Authority (3rd Party)	2,954	0	0	2,954	3,013	0	0	3,013
	Substation and Line Routine Maintenance	8,396	0	0	8,396	8,564	0	0	8,564
	Emergency Response	0	3,050	0	3,050	0	3,111	0	3,111
	Forestry	0	8,476	0	8,476	0	8,646	0	8,646
	Environmental	2,419	0	0	2,419	2,467	0	0	2,467
	Other (Material, Fleet, Insurance)	757	209	419	1,385	773	213	427	1,412
	Sub-Total	*16,375*	*13,584*	*419*	*30,378*	*16,703*	*13,856*	*427*	*30,986*
Overhead Costs Allocated to OM&A	Labour and Departmental Costs	1,739	0	5,451	7,189	1,773	0	5,560	7,333
	Environmental Services	0	0	0	0	0	0	0	0
	Other Consultants (Allocate)	0	0	1,132	1,132	0	0	1,155	1,155
	Indigenous Engagement & Communications	1,467	1,467	0	2,934	1,496	1,496	0	2,993
	Stakeholder Engagement	0	0	0	0	0	0	0	0
	Indigenous Participation and Training	0	0	1,016	1,016	0	0	1,037	1,037
	Administrative Costs	0	0	1,744	1,744	0	0	1,779	1,779
	Sub-Total	*3,205*	*1,467*	*9,343*	*14,015*	*3,270*	*1,496*	*9,530*	*14,296*
Total		**19,581**	**15,051**	**9,762**	**44,393**	**19,972**	**15,352**	**9,957**	**45,281**

1 – For the 5-year forecast WPLP has updated specific direct operating scopes as it relates to its expected preventative maintenance program for 2027 which includes Substation and Line Routine Maintenance, Forestry and Environmental.

2 – Other line items assumed a 2% CPI increase adjustment.

BOARD STAFF – 25

Reference: Exhibit F-3-1

Question(s):

a) Please discuss WPLP's budgeting process for the planned 2026 OM&A. How did WPLP determine the need of resource for 2026 in each of its three expense categories (Employee Compensation, Shared Service & Corporate Cost Allocation, and Purchase of Non-affiliate Services)?

Response:

a) WPLP has a robust, bottom-up budgeting approach for each of the expense categories.

For Employee Compensation, WPLP reviewed its existing labour resources and the additional labour resource requirements for 2026 to support its operations. WPLP is only adding positions based on its resource requirements for 2026. WPLP relies on historical information and Korn Ferry's established methodology to forecast compensation costs.

For Shared Services & Corporate Cost Allocation, WPLP identifies the scopes by which affiliates can support its day-to-day operations and identifies the forecasted hours required. The decision to use affiliate resources allows WPLP to retain highly qualified individuals on a temporary basis as it transitions to full operations and flexibility to transition them out as requirements are reduced or WPLP specific resource are obtained. The costs incurred from FortisOntario is more than offset by what cost could be if WPLP had to directly employ the same functions on a full-time basis. In addition, OSLP is able to provide valuable community connections and Indigenous knowledge and protocols to ensure WPLP is consistent with its Indigenous engagement efforts. Rates for 2026 are forecasted on pre-determined hourly rates for various positions and levels of seniority as noted in Exhibit F-3-1.

Purchases of Non-Affiliate Services are prepared based on identified scopes and deliverables required. Where applicable, WPLP uses existing agreements (ex. IMER, HONI Agreement, Giiwedin Agreement) to forecast 2026 resource requirements. For services WPLP does not have an existing contract for, WPLP has worked with vendors to obtain estimates or used information from other FortisOntario subsidiaries where available.

BOARD STAFF – 26

Reference: Exhibit F-3-1 / Section B and Section C

Preamble: WPLP discussed the services received from affiliates/related parties as well as the service purchased from non-affiliate third parties in Section B and Section C of Exhibit F-3-1.

Question(s):

a) How many contractors and subcontractors (i.e. affiliates/related parties and third parties) has WPLP engaged for operations, maintenance, capital projects, vegetation management, environmental services, and other functions? Please provide this information (list all parties with their corresponding functions) in one table.

b) For each major contract, please indicate whether the procurement process was competitive or sole-sourced.

c) How many bids were received for each competitively procured contract?

d) What criteria were used to evaluate bids?

e) Please confirm whether WPLP's shared service practices (receiving service from affiliates and other related parties) are compliant with the OEB's Affiliate Relationships Code For Electricity Distributors and Transmitters. If not, please explain why.

f) OEB staff compiled the following table based on information provided in Table 5-Third-Party Costs by Year of Exhibit F-3-1. Please complete the table by filling the empty cells. In the cell for "Actual 2025", please provide the sum of the most up-to-date 2025 actual (as of September 2025) and current forecast for the remaining of the year.

	2022 (EB-2021-0134)	**2023 (EB-2022-0149)**	**2024 (EB-2023-0168)**	**2025 (EB-2024-0176)**	**2026 (EB-2025-0192)**
Proposed (A)			32,632,638	26,017,018	28,429,347
Actual (B)	20,372,148	23,392,768	24,650,363		N/A
Cost Over-estimated C=A-B			7,982,275		N/A

g) For any significant variances between proposed and actual third-party cost identified in the last row of the table in part e), please provide explanations.

Response:

a) In respect of the 2026 test year, WPLP has engaged 22 contractors, which are listed along with corresponding functions in Attachment A.

b) Please see table below summarizing the procurement process for major contracts (above materiality)[1].

Major Contract	Procurement Process
FortisOntario	Sole Source
Giiwedin Environmental Services	Competitive
Hydro One Networks Inc	Sole Source
OSLP	Sole Source
Powertel Utilities Contractors Limited	Competitive

c) Please see table below that provides bids received on competitively procured contracts.

Major Contract	Number of Bids Received
Giiwedin Environmental Services	2
Powertel Utilities Contractors Limited	2

d) Criteria used to evaluate the bids for competitively procured contracts included historical performance of proponents, project approach/understanding of services and quality requirements, health, safety and environmental program, project structure and proposed personnel along with Indigenous participation plan and financial (price).

e) The services arrangement with WPLP's affiliate, OSLP, is materially consistent with the ARC with pricing based on independent benchmarking of labour costs for comparable services. However, the agreement has been in effect for a period in excess of five years as it was put in place in advance of construction and energization of the facilities. WPLP is committed to undertaking a review and refresh of this agreement at the earliest opportunity to maintain compliance with the ARC.

f) Please see table below with updated empty cells and 2025 actuals (up to August 2025, given

[1] This table does not include the costs for WPPM, which are provided in the employee compensation expense category within this 2026 rate application.

September close is not available) and 2025 forecasted costs.

	2022 (EB-2021-0134)	**2023 (EB-2022-0149)**	**2024 (EB-2023-0168)**	**2025 (EB-2024-0176)**	**2026 (EB-2025-0192)**
Proposed (A)	27,531,256	31,157,605	32,632,638	26,017,018	28,429,347
Actual (B)	20,372,148	23,392,768	24,650,363	August Actuals: 11,539,327 Remaining Forecast: 12,334,769	N/A
Cost Over-estimated C=A-B	7,159,108	7,764,837	7,982,275	2,142,922	N/A

g) Please note that WPLP is responding to variances between proposed and actual third-party costs identified in the table in response (f). For the variances in 2022 and 2023, they are primarily driven by savings with third-party supports related to the construction Project, which include owner engineer, independent engineer, legal and other consultant cost savings. WPLP has provided an explanation on the variance for 2024 in response to Board Staff 29 (a) and on the variance for 2025 as part of the response to Board Staff 29 (b). WPLP expects that, as construction is no longer being undertaken, these large variances are not anticipated to occur in 2026 test year.

Attachment A - Board Staff - 26 (a)
WPLP list of Contractors and Subcontractors

#	Contractors	Function	Activity
1	Adam F. Fiddler	Administration	Legal Counsel
2	CEATI International Trust	Operations	Membership Industry Practices
3	Draco (1985) Ltd	Operations	Storage rental and snow clearing
4	Ernst & Young	Administration	Auditor
5	Forest Helicopters Inc	Operations	Helicopter Services
6	FortisOntario	Operation and Administration	See page 11 of Exhibit F-3-1 for services provided by FortisOntario
7	Giiwedin Environmental Services	Environmental Services	Environmental monitoring service provider
8	HYDRO ONE NETWORKS INC	Operations	Control room services
9	John Cutfeet	Administration	Translation services
10	KBM RESOURCES GROUP	Operations	GIS and vegetation management services
11	Missabay Contracting LP	Vegetation Management/Operations	Vegetation Management
12	Mott MacDonald Canada Limited	Capital Projects	Independent Engineer Services
13	Obish Construction Ltd Partnership	Vegetation Management	Vegetation Management services including danger tree removal.
14	Olthuis Kleer Townshend LLP	Administration	Legal Counsel
15	Opiikapawiin Services LP	Operation and Administration	See page 11 of Exhibit F-3-1 for services provided by Opiikapawiin Services LP
16	POWERTEL UTILITIES CONTRACTORS LIMI	Operations and Maintenance and Capital Project	Inspection and Maintenance provider under IMERS Agreement.
17	PRICEWATERHOUSECOOPERS LLP	Administration	Financing Consultant
18	ServiceMaster Clean	Administration	Janitorial Services
19	TORYS LLP	Administration & Capital Projects	Legal Counsel
20	TW POWER SUPPLY LTD	Operations	Transmission line part supplier
21	WHITEFEATHER FOREST COMMUNITY	Operations	Snow clearing services
22	Wisk-Air Limited	Operations	Helicopter Services

BOARD STAFF – 27

Reference: Exhibit F-3-1 / pages 8-9 / Table 2
EB-2024-0176 / Exhibit F-3-1 / Table 2

Preamble: Table 2 – "Employee Compensation Breakdown" provides a breakdown of total employee compensation costs for 2021-2026. Table 2 shows that WPLP's 2026 planned compensation costs (in all components) are projected to increase for both Management and Non-Management compared to 2025 Forecast.

Question(s):

a) Please confirm the FTE numbers shown in Table 2 are average FTEs or year-end FTEs.

b) Page 9 of Exhibit F-3-1 states that "Total compensation costs increased year-over-year during the 2022 to 2024 period, coinciding with WPLP's growing needs over the construction period." However, Table 2 shows 2024 actual FTEs and compensation costs decreased from 2023. It's also noted that the 2024 actual FTEs and compensation costs in all components for both Management and Non-Management decreased from the 2024 forecast level as provided in WPLP's 2025 Revenue Requirement application.

Please provide explanations for the reductions in 2024 actual FTEs as well as compensation costs (compared to both 2023 actual and 2024 forecast). Please also explain why this trend contradicts the above noted narrative on page 9 of Exhibit F-3-1.

c) Please insert a column "2025 Updated Forecast" in Table 2 between the two columns of "2025 Forecast" and "2026 Plan". The new column should include the most up-to-date 2025 actuals (as of September 2025) and current forecast for the remaining of 2025. If this updated forecast for 2025 cannot be provided, please discuss the reasons.

d) Please provide a breakdown of 2024 (actual), 2025 (updated forecast) and 2026 FTEs into detail of positions. Please discuss and explain the changes between 2024 and 2025, and between 2025 and 2026, on position level.

Response:

a) The FTE numbers shown in Table 2 are the year-end FTEs.

b) The reduction in forecasted FTE for 2024 vs actuals for 2024 is the result of delayed hiring of the Manager of Indigenous Relations, an electrical engineer, P&C Engineer and

Forestry Coordinator. The reduction of 1 FTE from 2023 to 2024 is the result of loss of Environmental Manager supporting construction EA commitments.

There is a reduction in compensation costs for 2024 forecast and actuals due to planned delays in hiring of planned positions. Compensation costs from 2023 to 2024 decreased as 2023 included a one-time contract retention incentive.

The sentence should be updated as follows, "Total compensation costs increased year-over-year during the 2022-2023 period, coinciding with WPLP's growing needs over the construction period. The decrease from 2023 to 2024 is primarily driven by a one-time contract retention incentive incurred in 2023."

c) Please see table below with 2025 actuals (up to August 2025, given September close is not available) and 2025 forecasted costs. WPLP has not re-forecasted total costs for 2025 as it still plans to recruit for operations positions and is unable to forecast permanent savings at this time. Any savings will be recorded in OM&A Variance Account and be returned to rate payers in a future application.

	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast	2025 Actuals to August	2025 Forecast Sept-Dec	2026 Plan
Number of Employees (FTEs including Part-Time)								
Management (including executive)	12	12	12	11	9	8	9	9
Non-Management (all non-union)	14	15	19	19	18	16	18	21
Total	**26**	**27**	**31**	**30**	**27**	**24**	**27**	**30**
Total Salary and Wages including overtime and incentive pay								
Management (including executive)	$2,335,708	$2,735,577	$2,973,922	$2,619,391	$1,790,691	$1,112,886	$677,805	$1,948,877
Non-Management (all non-union)	$912,428	$1,327,607	$1,659,043	$1,572,230	$2,090,934	$1,232,584	$858,350	2,382,269
Total	**$3,248,136**	**$4,063,184**	**$4,632,965**	**$4,191,620**	**$3,881,624**	**$2,345,470**	**$1,536,156**	**$4,331,146**
Total Benefits (Current + Accrued)								
Management (including executive)	$317,038	$357,246	$416,349	$420,671	$268,604	$175,691	$92,913	$292,332
Non-Management (all non-union)	$127,338	$205,631	$232,266	$252,498	$313,640	$194,209	$119,431	$357,340
Total	**$444,376**	**$562,876**	**$648,615**	**$673,170**	**$582,244**	**$369,900**	**$212,344**	**$649,672**
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$2,652,746	$3,092,823	$3,390,271	$3,040,062	$2,059,294	$1,288,577	$770,718	$2,241,209
Non-Management (all non-union)	$1,039,766	$1,533,238	$1,891,309	$1,824,728	$2,404,574	$1,426,793	$977,781	$2,739,609
Total	**$3,692,512**	**$4,626,060**	**$5,281,580**	**$4,864,790**	**$4,463,868**	**$2,715,369**	**$1,748,500**	**$4,980,818**
Total Allocated to Capital	$3,549,118	$3,755,747	$2,368,370	$887,006	-			-
Total Allocated to Distribution Deferral Account (Pikangikum)	$143,394	$118,942	$70,178	-	-			-
Total Allocated to OM&A	-	$751,371	$2,843,033	$3,977,784	$4,463,868	$2,715,369	$1,748,500	4,980,818

d) Please see table below of breakdown of 2024 (actual), 2025 (updated forecast) and 2026 FTEs into detail of positions.

	2024 Actual	2025 Forecast	2026 Forecast	Change 2024 to 2025	REF	Change 2025 to 2026	REF
Chief Executive Officer	1	1	1	0		0	
Chief Operating Officer	1	1	1	0		0	
Director Finance	1	1	1	0		0	
Project Director	1	0	0	-1	[A]	0	
Manager Accounting	1	1	1	0		0	
Manager Procurement	1	1	1	0		0	
Manager Indigenous Relations	0	1	1	1		0	
Manager Communications	1	1	1	0		0	
Manager Operations	1	1	1	0		0	
Health, Safety and Environment Manager	1	1	1	0		0	
Manager Construction	1	0	0	-1	[A]	0	
Elder Advisor	1	1	1	0		0	
Cost/Reporting Accountant	1	1	1	0		0	
Jr Financial Administrator	1	1	1	0		0	
Lands Coordinator	1	1	1	0		0	
IT Administrator	0	0	1	0		1	[D]
Sr HR Advisor	1	1	1	0		0	
Jr HR Advisor	1	1	1	0		0	
Receptionist	1	1	1	0		0	
Jr System Monitoring and Compliance Position	0	0	1	0		1	[E]
Transmission Line Lead	1	1	1	0		0	
Sr Electrical Engineer	1	1	1	0		0	
Asset Management Lead	1	1	1	0		0	
Sr System Monitoring and Compliance Position	0	1	1	1	[B]	0	
Electrical E.I.T.	1	1	1	0		0	
Operations Technologist	1	1	1	0		0	
Forestry Coordinator	0	1	1	1	[C]	0	
Substations Lead	1	1	1	0		0	
Health & Safety Lead	1	1	1	0		0	
Environmental Lead	1	1	1	0		0	
Environmental Compliance Coordinator	1	0	1	-1	[A]	1	[F]
Executive Assistant	1	1	1	0		0	
Administrative Assistant	1	0	0	-1	[A]	0	
Project Controls Coordinator	1	0	0	-1	[A]	0	
Environmental Coordinator	1	0	0	-1	[A]	0	
	30	**27**	**30**	**-3**		**3**	

[A] Given conclusion of construction activities these positions are no longer required as focus was on construction activities on the Project.
[B] System monitoring and compliance which would include managing IESO outage requests, coordinating work protection and holdoffs between HONI control room and WPLP's service providers, monitoring and logging substation access, providing situational awareness for reliability risk and outage/emergency response. WPLP is in the process of developing a job description to recruit before the end of 2025.

[C] Given ramp of vegetation management program development and field activities, additional supports are required. WPLP is in the process of developing a job description to recruit before the end of 2025.
[D] Required additional IT support within the Thunder Bay office to increase efficiencies. WPLP has successfully recruited this position in 2025.
[E] Additional support for system monitoring and compliance with troubleshooting alarms, monitoring reliability risks etc. WPLP is in the process of developing a job description to recruit before the end of 2025.
[F] Additional support for environmental monitoring program given the magnitude of program for post-construction commitments. WPLP is in the process of developing a job description to recruit before the end of 2025.

BOARD STAFF – 28

Reference: Exhibit F-3-1 / pages 12-13 / Table 3
EB-2024-0176 / Exhibit F-3-1 / Table 3

Preamble: Table 3 – "Affiliate and Related Party Costs by Year" shows the 2021-2025 costs charged to WPLP from affiliates and related parties. The application states that affiliate costs are trending down since 2024, and WPLP has continued to focus on cost savings as it has transitioned from capital project construction to full operations.

Question(s):

a) The application states that "affiliate costs are trending down since 2024, and WPLP has continued to focus on cost savings as it has transitioned from capital project construction to full operations." However, the 2024 actual cost in Table 3 in amount of $5,182,269 is lower than the 2025 forecast of $5,234,477. It's also noted that the 2024 actual cost is lower than the 2024 forecast level of $5,412,510 as provided in WPLP's 2025 Revenue Requirement application.

   Please provide explanations for the lower 2024 actual affiliated and related party costs (compared to both 2025 forecast and 2024 forecast). Please also explain why the lower 2024 cost contradicts the above noted narrative on page 13 of Exhibit F-3-1.

b) Please insert a column "2025 Updated Forecast" in Table 3 between the two columns of "2025 Forecast" and "2026 Plan". The new column should include the most up-to-date 2025 actuals (as of September 2025) and current forecast for the remaining of 2025. If this updated forecast for 2025 cannot be provided, please discuss the reasons.

c) Based on the updated table provided in part b), please confirm if the statement about affiliate cost trending referenced in the Preamble is still true.

d) Based on the updated table provided in part b), please provide explanation for the variance between 2024 and 2025 and the variance between 2025 and 2026. What are the cost drivers? Please provide the associated changes in the services received (and to be received) from Fortis and OSLP and the rationale for the changes.

Response:

a) WPLP has trended actuals below the forecasted amounts as it has continued to focus on cost savings as it transitioned from construction to full operations. WPLP notes that

affiliate costs relate only to OSLP and FNLP, which have been trending down from 2024 to 2026.

As it relates to 2024 actuals vs 2024 forecast, WPLP had savings of $230K primarily driven by savings from our indigenous participation activities given the early conclusion of construction activities in 2024.

As a result of a full year of the CFO/VP of finance position and seconding a Vegetation Management Lead from Fortis subsidiaries, WPLP sees an increase from 2024 actuals to 2025 forecast. This is partially offset by reductions in OSLP services related to participation as WPLP transitions from construction support to operations support.

b) Please see table below that provides actuals to 2025 (up to August, given September close is not available) and current forecast for remaining 2025. WPLP has not re-forecasted total costs for 2025 as expenditures are timing dependent and variances in spend are expected to be incurred by end of year. WPLP expects a ramp up of activities in Q3/Q4 related to engagement on the vegetation management program within the communities and Indigenous workforce development activities. If savings are identified, they will be recorded in OM&A Variance Account and be returned to rate payers in a future application.

Name of Company		Service Offered	Cost for the Service ($)							
From	To		2021	2022	2023	2024	2025	2025	2025	2026
			Actual	Actual	Actual	Actual	Actuals	Forecast	Total Forecast	Plan
Fortis Subsidiaries	WPLP	Multiple per Services Contract	1,705,252	1,745,527	1,640,879	2,125,422	1,245,947	1,087,980	2,333,927	2,405,767
OSLP and FNLP	WPLP	Multiple per Affiliate Contract	2,822,838	2,885,790	3,044,327	3,056,847	1,210,390	1,690,160	2,900,550	2,537,877
Total:			**4,528,090**	**4,631,318**	**4,685,206**	**5,182,269**	**2,456,337**	**2,778,140**	**5,234,477**	**4,943,644**

c) Confirmed.

d) For 2024 to 2025, the additional drivers of cost within Fortis are the result of Vegetation Management Lead and CFO services being provided for the full period of 2025 under the services agreement. The use of services allows WPLP to use highly skilled individuals as required and reduce costs. The increase in costs incurred from Fortis is more than offset by the costs if WPLP had to directly employ the CFO function on a full-time basis in 2025. The drivers of savings for OSLP related to reduced training program facilitation. For further detail, see WPLP's response to OEB Staff 33(a) in the 2025 application (EB-2024-0176).

As it relates to 2025 to 2026, WPLP will be receiving some additional support from Fortis for internal control and regulatory support in 2026. The increase in costs incurred

from Fortis is more than offset by the costs if WPLP had to directly employ the same functions on a full-time basis. The drivers of savings for OSLP relate to updates to engagement activity and workforce development support for operational programs.

BOARD STAFF – 29

Reference: Exhibit F-3-1 / page 15 / Table 5
EB-2024-0176 / Exhibit F-3-1 / page 15 / Table 5

Preamble: Table 5 – "Third-Party Costs by Year" shows WPLP's 2021-2026 annual non-EPC costs related to the purchase of goods and services from third parties.

Question(s):

a) It's noted that the 2024 actual total third-party cost of $24,650,363 decreased from the 2024 forecast level of $31,494,763 as presented in WPLP's 2025 Revenue Requirement application by about 22%. Please provide explanations for this reduction.

b) Table 5 shows that the 2025 forecast third-party cost in O&M Service Providers category is in amount of $15,834,634, which is different than the 2025 forecast cost in this category provided in WPLP's 2025 Revenue Requirement application (in amount of $17,977,556). Please provide explanations for this discrepancy, or make necessary corrections to Table 5.

c) Please insert a column "2025 Updated Forecast" in Table 5 between the two columns of "2025 Forecast" and "2026 Plan". The new column should include the most up-to-date 2025 actuals (as of September 2025) and current forecast for the remaining of 2025. If this updated forecast for 2025 cannot be provided, please discuss the reasons.

d) Based on the updates made to Table 5 in parts b) and c), please provide explanation for the variance between 2024 and 2025, and variance between 2025 and 2026. What are the cost drivers? Please provide the associated changes in the third-party goods and services purchased (and to be purchased) and the rationale for the changes.

Response:

a) Significant drivers of savings for third party costs in 2024 included (1) savings on Owner Engineer and other Project Support services ($2.2 million) as noted in response to Board Staff 8 (a), (2) savings related to engagement and Indigenous participation services as a result of reduced construction activities in 2024 and transition to operational support services ($2.1 million), (3) savings related to operation programs and emergency response requirements ($1.5 million), (4) savings related to delay in software requirements given delays in implementation ($0.4 million), (5) savings on Lidar scope as noted in response to Board Staff 8(a) ($1.3 million), and (6) other savings on legal and consultant services and other departmental cost savings ($0.5 million).

b) The 2025 forecast was updated based on the settlement OM&A cost envelope resulting from the 2025 rate proceeding. These savings were found through savings in the deferral of the LiDAR program, and savings in snow clearing and general material requirements.

c) Please see table below with 2025 actuals (up to August 2025, given September close is not available) and 2025 forecasted costs. WPLP has not re-forecasted total costs for 2025 as the timing of expenditures within the operating year varies. WPLP experienced significant wildfires on the project during the summer, delaying inspection, engagement travel and vegetation management activities to Q3/Q4 and expects these activities to ramp up for the remainder of the year. Any savings identified at year end will be recorded in OM&A Variance Account and be returned to rate payers in a future application.

Cost Category	2022 Actual	2023 Actual	2024 Actual	2025 Forecast	2025		2026
					Actuals	Forecast	Plan
Indigenous Engagement, Indigenous Participation, Communication	2,961,282	3,769,022	3,049,496	1,968,700	729,099	1,239,601	1,928,700
Admin, Office, Fleet and Support	1,107,051	820,634	344,466	364,000	222,526	141,474	349,000
O&M Service Providers	1,658,216	4,086,694	8,611,792	15,834,634	7,946,251	7,888,383	21,328,131
Overheads and Easement/Access Fees	2,858,659	3,612,086	4,305,570	3,649,312	2,044,380	1,604,932	3,811,006
Consulting, Professional and Advisory	11,786,940	11,104,332	8,339,039	2,057,450	597,072	1,460,378	1,012,511
Total	**20,372,148**	**23,392,768**	**24,650,363**	**23,874,096**	**11,539,327**	**12,334,769**	**28,429,348**

d) The variance between 2024 and 2025 is driven by the conclusion of construction activities in 2024 and transition to full operations in 2025, with costs shifting from Consulting, Professional and Advisory service that supported construction to O&M service providers supporting our operations and maintenance program. Additional details on the operating programs are provided in response to Board Staff 23. The variance between 2025 and 2026 is primarily driven by (1) ramp up of WPLP's vegetation management planning and field activities given the timing for when the right of way was cleared, with assumption of 50% of a typical annual brushing cycle, resulting in an additional $3.5 million cost from prior year, and (2) additional line inspection (including LiDAR scope not carried out in 2025) and substation activities resulting in an additional $1.8 million from the prior year. These additions are partially offset by savings in professional services and department overhead costs of $0.7 million.

BOARD STAFF – 30

Reference: Exhibit F-3-1 / page 16 – Regulatory Costs
EB-2024-0176 / Exhibit F-3-1 / page 16 – Regulatory Costs

Preamble: In Reference 2, WPLP stated that it had included in its proposed 2025 OM&A costs the forecasted regulatory costs for the 2026 test year's revenue requirement application (anticipated to be filed in 2025). The regulatory costs for the filing were estimated to be $300,000.

In Reference 1, WPLP stated that WPLP's anticipated regulatory costs associated with the current application (2026 test year application) are part of its forecasted OM&A costs to December 31, 2025. WPLP has included its costs for OEB assessment in the current application, in the amount of $40,000.

Question(s):

a) With respect to the regulatory costs associated with the current 2026 test year's revenue requirement application, please explain how WPLP has addressed the discrepancy discussed in the Preamble.

b) The application notes that this cost is included in the services from non-affiliated envelope. Please indicate under which OM&A cost source and category WPLP allocated the regulatory cost (with reference to the associated Table in Exhibit F-3-1).

Response:

a) There is no discrepancy. WPLP included in our regulatory forecast $300,000 for third party filing costs and in addition included $40,000 for the OEB assessment of the 2026 rate application. These costs were included in the 2025 OM&A envelope. The costs to complete the 2026 rate application were included as part of WPLP's 2025 revenue requirement and have not included any filing costs within the requested OM&A envelope for 2026 test year.

b) The costs were included in consulting, professional and advisory service line within table 5 of Exhibit F-3-1 of the 2025 rate application.

BOARD STAFF – 31

Reference: Exhibit F-5-1 / Appendix A
Exhibit F-5-1 / Appendix A

Preamble: Per Reference 1 & 2, OEB staff has complied a table as below, showing the loss carry forward balance in 2025 revenue requirement application and the current application.

($000's)	Ref 2	Ref 1
Opening Losses Carryforward	-89,930	-89,821 (b)
Losses (Incurred)/Utilized during the year	-6,489	-4,098
Closing Losses Carryforward	-96,419 (a)	-93,919

Based on the table above, OEB staff notes that there is difference of $6,598,000 ((b)-(a)) between the closing loss carryforward balance in Ref 2 and the opening loss carryforward balance in Ref 1.

Question(s):

a) Please confirm the opening loss carryforward balance in this application.

i. If confirmed, please explain the variance identified above.

ii. Please update the evidence as applicable.

iii. Please provide the Loss Carryforward Continuity Schedule available for use as of 2026 by including the year of origination, amount utilized in 2026 and the remaining balance.

Response:

a) WPLP clarifies that the loss carry forward amount included in the current application was incorrect as it did not take into account the 2025 loss carry forward balance. Attached is an updated Exhibit F-5-1, Appendix A. This correction does not impact WPLP's proposed 2026 revenue requirement.

The table provided below presents a summary of loss carryforwards by year.

Forecasted Loss Carryforwards ($000s)		
Year	**Additions**	**Balance**
2019	2,811	2,811
2020	3,118	5,928
2021	2,677	8,605
2022	28,783	37,388
2023	38,305	75,693
2024	14,128	89,821
2025	6,288	96,109
2026	4,098	100,207

WPLP
Calculation of Utility Income Taxes
2026 Test Year
($000's)

SUMMARY OF TAX EXPENSE

	2026
First Nation LP	0
Fortis (WP) LP	596
Total	**596**

WPLP

Line No.	Particulars		2026	
	Determination of Taxable Income			
1	Regulatory Net Income (before tax)		45,074	(1)
2	Book to Tax Adjustments:			
3	Depreciation and amortization		26,864	
4	Capital Cost Allowance		-80,301	
5	Other		0	
6	Total Adjustments	$	-53,437	
7	Regulatory Taxable Income/(Loss) before Loss Carry Forward	$	-8,364	
	Allocation of Taxable Income			
8	First Nation LP (51%)		-4,265	
9	Fortis (WP) LP (49%)		-4,098	
10	Total	$	-8,364	
	Tax Rates			
11	Federal Tax		15.00	%
12	Provincial Tax		11.50	%
13	Total Tax Rate		26.5	%

(1) The regulated income of $44,477,388 provided in G-2-1 Table 1 has been grossed up for tax purposes.

WPLP
Calculation of Utility Income Taxes
2026 Test Year
($000's)

First Nation LP

Line No.	Particulars		2026	
	Determination of Taxable Income			
1	Allocation of Taxable Income from WPLP		-4,265	
4	Tax Rate		0.00	%
5	**Income Tax Expense**	**$**	**0**	
	Determination of Corporate Minimum Tax			
	Allocation of Accounting Income from WPLP		22,988	
	Corporate Minimum Tax Rate		0.00	%
	Corporate Minimum Tax Payable (Utilized)	**$**	**0**	
	Total Taxes Expense for First Nation LP	**$**	**0**	

WPLP
Calculation of Utility Income Taxes
2026 Test Year
($000's)

Fortis (WP) LP

Line No.	Particulars		2026	
	Determination of Taxable Income			
1	Allocation of Taxable Income from WPLP		-4,098	
2	Loss Carryforward		4,098	
3	Taxable Income after Loss Carryforward		0	
4	Tax Rate		26.50	%
5	**Income Tax Expense**	**$**	**0**	
	Loss Continuity Schedule			
6	Opening Losses Carryforward		-96,109	
7	Losses (Incurred)/Utilized during the year		-4,098	
8	Closing Losses Carryforward		-100,207	
	Determination of Corporate Minimum Tax			
9	Allocation of Accounting Income from WPLP		22,086	
10	Corporate Minimum Tax Rate		2.70	%
11	Corporate Minimum Tax Potentially Applicable		596	
12	Ontario Income Tax		0	
13	**Corporate Minimum Tax Payable (Utilized)**	**$**	**596**	
14	Opening CMT Credit Carryforward		1,688	
15	CMT Credit Incurred/(Utilized)		596	
16	Closing CMT Credit Carryforward		2,284	
17	**Total Taxes Expense for Fortis (WP) LP**	**$**	**596.325**	

BOARD STAFF – 32

Reference: WPLP_F-5-1_2026 WPLP Income Tax and CCA Calculations_20250704
Exhibit F-5-1 / Part F
Exhibit G-2-1 / Table 1

Preamble: Per Reference 1, WPLP calculates the 2026 Regulatory Net Income (before tax) which is $45,074K and states the regulated income of $44,477,388 provided in G-2-1 Table 1 has been grossed up for tax purposes.

Per Reference 2, WPLP confirms that its forecasted 2026 regulatory net income before tax is equal to the return on equity component of its revenue requirement, as calculated in G-2-1.

Per Reference 3, WPLP calculates 2026 ROE which is $44,477,388.

Question(s):

a) Please confirm whether the 2026 Regulatory Net Income (before tax) in Reference 1 is calculated based on grossing up the 2026 ROE in Reference 3.

b) If a) is confirmed, please explain and show the calculation WPLP is using to gross up the ROE to the Regulatory Net Income (before tax).

c) If a) is confirmed, please explain why WPLP calculates regulatory net income (before tax) by grossing up the ROE.

d) If a) is not confirmed, please explain how the Regulatory Net Income (before tax) is calculated.

Response:

a) Confirmed.

b) The table below provides the calculation of grossed up Regulatory Net Income to ensure that WPLP maintains the return ROE identified in Exhibit G-2-1.

	Ref	WPLP
OM&A	**A**	38,353,810
Depreciation Expense	**B**	26,863,558
Interest Expense	**C**	33,790,462
Target ROE	**D**	44,477,388
Adj to Taxable Income		
Tax Rate	**E**	2.7%
% Taxable	**F**	49.0%
Income Taxes	**G=DxExF**	588,436
Income Taxes (Grossed Up)	**H=D/(1-(BxC))**	596,325
Revenue Requirement	**G=A+B+C+D+H**	144,081,543
Less OM&A	**A**	-38,353,810
Less Depreciation	**B**	-26,863,558
Less Interest	**C**	-33,790,462
Net Income (Before Tax)	**I=G-A-B-C**	45,073,714

c) WPLP ROE and Regulatory net income would be the same number and to ensure the ROE provided in Exhibit G-1-2 is achieved, WPLP grosses up the Target ROE.

d) Not applicable.

BOARD STAFF – 33

Reference: Exhibit F-5-1 / Part E
WPLP_F-5-1_2026 WPLP Income Tax and CCA Calculations_20250704 / Tab CCA

Preamble: Per Reference 1, WPLP states that CCA calculation for the 2026 test year includes the effect of Accelerated CCA (AIIP).

OEB staff notes that the CCA amount is calculated based on legacy half-year rule per Reference 2 instead of applying AIIP.

Question(s):

a) Please confirm OEB staff's observation that WPLP is not applying AIIP for the 2026 test year.

   i. If confirmed, please update the evidence as needed.

b) Please complete the following table compiled by OEB staff.

($000's)	**WPLP's current calculation (NOT applying AIIP in 2026)**	**WPLP is applying AIIP phase out**
CCA amount	$83,301	
Allocation of Accounting Income - Fortis (WP) LP	$22,086	
Total income tax expenses for 2026 test year	$596	

c) Please provide the revenue requirement impact if the AIIP is being applied.

Response:

a) Confirmed.

b) Please see table below updated table compiled by OEB.

($000's)	**WPLP's current calculation (NOT applying AIIP in 2026)**	**WPLP is applying AIIP phase out**

CCA amount	$83,301[1]	80,673
Allocation of Accounting Income - Fortis (WP) LP	$22,086	$22,086
Total income tax expenses for 2026 test year	$596	$596

c) There would be no revenue requirement impact as the corporate minimum tax is not impacted by CCA claimed.

[1] WPLP updated the OEB amount to the amount presented in 2026 rate application.

BOARD STAFF – 34

Reference: Exhibit G-1-1 / Table 1
Exhibit I-1-1 / Table 1
WPLP_C-3-1_2024-2026 FA Cont and Depr Sched_20250704

Preamble: Reference 2 shows that the 2026 Accumulated Depreciation (ave.) is in amount of $87,914,125. Reference 2 and Reference 1 indicate the total Rate Base is in amount of $1,235,483,010.

On Tab "2026 Combined" of Reference 3, the average of opening accumulated depreciation and closing accumulated depreciation is in amount of $87,914,312.

Question(s):

a) Please provide explanation for the discrepancy noted above for 2026 Average Accumulated Depreciation (with calculation details).

b) Otherwise, please make necessary corrections to 2026 Average Accumulated Depreciation value and all resulting revenue requirement parameters in related evidence in the application (including the referenced materials above).

Response:

a) The discrepancy is the result of an error in the opening balance of Contributions & Grants, which has been updated in WPLP C-3-1 2024-2026 FA Cont and Depr Sched for the $187 difference. The updated FA continuity is provided as Attachment 1 hereto (filed as live Excel), with 2026 average Accumulated Depreciation [(74,482,346 + 101,345,903)/2] equals $87,914,125. This is consistent with amounts used to calculate total rate base of $1,235,483,101. No further updates to the application or evidence are required.

b) Please see update to C-3-1 2024-2026 FA Cont and Depr Sched provided in response to Board Staff 34 (a) above. No further updates to the application or evidence are required.

BOARD STAFF – 35

Reference: Exhibit G-2-1 / pages 1-4
Exhibit G-2-1 / Table 1
Exhibit G-2-1 / Table 2

Preamble: The application states that the debt structure between Ontario and Senior Banks changes from 66:34 to 49:51 given the CIAC contribution from the Trust is only used to pay down the Ontario Facility, as prescribed within Trust Agreement.

Question(s):

a) Please provide the calculation for the updated long-term debt structure between Ontario and Senior Banks of 49:51.

b) Please provide the related reference in the Trust Agreement describing the mechanism of how the CIAC contribution should be used to pay down the Ontario Facility.

c) With respect to Table 2 in Exhibit G-2-1, please provide detailed calculations for the 2026 Principal and 2026 Interest & Fees amounts for Ontario Facility and Senior Bank Facility.

d) Please explain why the Total 2026 Principal in Table 2 of Exhibit G-2-1 (in amount of $961,003,724) does not equal the Long-term Debt amount in Table 1 (in amount of $691,870,486). Please provide explanation for the difference.

e) What would be the long-term debt rate calculated in Table 2 if the input for total 2026 principal is $691,870,486?

Response:

a) The forecasted debt make up of Ontario and Senior Bank facilities is provided in Table 2 of Exhibit G-2-1 and agrees to the debt split provided in WPLP's 2024 audited financial statements. In addition, the table provided in response to OEB Staff 35(c) below, provides the forecasted principal amount for Ontario and Senior Banks.

b) Section 4 "Distributions" of the original Trust Agreement outlines how distributions (CIAC) out of the independent trust are to be applied. Specifically, Section 4.2 provides a waterfall outlining the distributions out of the independent trust. WPLP has provided the reference in the distribution waterfall in Section 4.2 that relates to the Ontario Facility:

> "first, to Ontario pursuant to an irrevocable direction in the form of Exhibit B delivered by Watay to the Trustee on the date hereof, an amount equal to the lesser of (A) the Ontario Loan Obligations; and (B) the Capital Contribution, each as set out in the Statement of Distributions;"

WPLP confirms the first distribution outlined in Section 4.2 requires the first payment under the distribution waterfall to be made to the Ontario Facility and that the CIAC was only sufficient to pay a portion of the outstanding Ontario Facility in 2024.

c) The table below provides detailed calculations for Principal and 2026 Interest and Fees.

2026 Cost of Financing

	31	28	31	30	31	30	31	31	30	31	30	31		
Month Ending	**31-Jan-26**	**28-Feb-26**	**31-Mar-26**	**30-Apr-26**	**31-May-26**	**30-Jun-26**	**31-Jul-26**	**31-Aug-26**	**30-Sep-26**	**31-Oct-26**	**30-Nov-26**	**31-Dec-26**	**Average**	**Total**
Forecasted Loan Balances from Financing Model														
ON Loan Balance	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	466,123,520	
SB Loan Balance	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	494,880,204	
TOTAL	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	**961,003,724**	
Forecasted Cost of Debt from Financing Model														
ON Interest & Fees	2,735,652	2,993,276	39,589	1,970,977	2,277,891	38,312	2,037,400	2,277,891	38,312	2,037,400	2,252,284	39,589		18,738,571
SB Interest & Fees	2,166,791	1,957,102	2,166,791	2,096,895	2,166,791	2,096,895	2,166,791	2,166,791	2,096,895	2,166,791	2,096,895	2,166,791		25,512,220
TOTAL	**4,902,443**	**4,950,378**	**2,206,380**	**4,067,872**	**4,444,682**	**2,135,206**	**4,204,192**	**4,444,682**	**2,135,206**	**4,204,192**	**4,349,179**	**2,206,380**		**44,250,791**
Cost of Debt	6.02%	6.73%	2.71%	5.16%	5.46%	2.71%	5.17%	5.46%	2.71%	5.17%	5.52%	2.71%		

Average Cost ON Loan	**4.02%**
Average Cost SB Loan	**5.16%**
Average Interest Rate	**4.60%**

d) The difference between the 2026 principal amount in Table 2 and the required long-term debt amount in Table 1 of Exhibit G-2-1 is the required outstanding debt to cover deferral account balances that are funded through the construction facility. Given the calculation used to calculate the long-term debt rate, the variance in balance has no impact on the Cost of Capital calculation.

e) The long-term debt rate would be calculated at the same value of 4.60% as provided in table 2 of Exhibit G-2-1.

BOARD STAFF – 36

Reference: WPLP_H-2-1-A_Continuity Tables for DVA_20250704
WPLP_H-1-1_Deferral and CWIP Continuity 2025_20250704

Preamble: Per Reference 1 & 2, OEB staff compiled the following table showing the difference of 2024 audited balance of principal and carrying charges between Reference 1 and Reference 2.

Account	Ref 1 (a)	Ref 2 (b)	Variance (a-b)
Construction Period Interest Cost Variance (Principle)	21,569,327	21,299,015	270,312
Construction Period Interest Cost Variance (Interest)	1,495,023	1,765,335	-270,312
Deferred Contingency Deferral Account (Principle)	243,262	241,499	1,763
Deferred Contingency Deferral Account (Interest)	13,124	14,888	-1,764
COVID 2020 Deferral Account (Principle)	4,349,913	3,656,869	693,044
COVID 2020 Deferral Account (Interest)	603,152	1,296,197	-693,045
Pikangikum Distribution Deferral Account (Principle)	634,004	363,726	270,278
Pikangikum Distribution Deferral Account (Interest)	59,123	329,401	-270,278
In-Service Date Variance (Principle)	5,439,257	6,768,494	-1,329,237
In-Service Date Variance (Interest)	92,973	-1,236,263	1,329,236

Question(s):

a) Please explain the variance identified in the table above and recalculate the interest based on the correct principal balance.

b) Please reconcile the amounts in Reference 1 and Reference 2 once a) is done.

c) Please update/resubmit both CWIP continuity and DVA continuity accordingly.

Response:

a) The variance was due to recovery of carrying charges being shown in H-1-1 Deferral and CWIP Continuity 2025 incorrectly within principal balance vs being shown against the carry charges incurred. There are no changes to carry charge required, but the updated Deferral and CWIP Continuity is provided in Attachment 1 hereto (filed as live Excel).
b) See updated continuity provided as part of response to Board Staff 36 (a) above.
c) Updated CWIP and DVA continuity has been provided as part of response to Board Staff 36 (a) above.

BOARD STAFF – 37

Reference: WPLP_H-1-1_Deferral and CWIP Continuity 2025_20250704
EB-2024-0176, Watay_Staff-45_H-2-1-A_Attachment A-Updated Continuity Tables for DVA_20240927

Preamble: Per Reference 1 & 2, OEB staff compiled the following table showing the difference of 2023 audited balance of principal and carrying charges between Reference 1 and Reference 2.

Account	Ref 1 (a)	Ref 2 (b)	Variance (a-b)
Pikangikum Distribution Deferral Account (Principle)	2,263,461	2,312,478	-49,017
Pikangikum Distribution Deferral Account (Interest)	248,262	199,245	49,017

Question(s):

a) Please explain the variance identified in the table above and recalculate the interest based on the correct principal balance.

b) Please reconcile the amounts in Reference 1 and Reference 2 once a) is done.

c) Please update/resubmit both CWIP continuity and DVA continuity accordingly.

Response:

a) Please see response to Board Staff 36 (a) providing updated Deferral and CWIP Continuity. As discussed, carry charge recovery was presented in principle column vs being netted against carrying charges incurred. Carrying charges are appropriately charged against the principal balance outstanding and no change to carrying charges is required.

b) Please see updated table in response to Board Staff 36 (a).

c) Please see updated table in response to Board Staff 36 (a).

BOARD STAFF – 38

Reference: OEB Prescribed interest rates
WPLP_H-2-1-A_Continuity Tables for Deferral and Variance Account Recovery_20250704

Preamble: The OEB released the Q4 2025 prescribed interest rate for deferral and variance accounts equaling 2.91%. WPLP is requesting final or partial disposition of audited balances of the deferral and variance accounts as at December 31, 2024, plus forecasted carrying charges for 2025 and 2026.

OEB staff notes that Q2 2024's interest rate of 3.16% has been applied to the schedule for both Q3 2025 and Q4 2025.

Question(s):

a) Please update the forecast carrying charges for Q3 2025 and Q4 2025 based on the OEB's published interest rate.

Response:

a) Please see Attachment 1 (filed as live Excel) for the H-2-1-A Continuity Tables for Deferral and Variance Account recovery with updated rates for Q3 and Q4 2025 and using Q4 2025 rate for forecasting 2026 rate.

BOARD STAFF – 39

Reference: EB-2024-0063, OEB Letter / July 26, 2024
EB-2024-0063, OEB Letter / October 31, 2024
EB-2024-0063, Decision and Order / March 27, 2025 / pp. 92
Exhibit H-1-1
WPLP_H-1-1_Deferral and CWIP Continuity 2025_20250704
WPLP_H-2-1-A_Continuity Tables for DVA_20250704

Preamble: On July 26, 2024, the OEB issued a Letter and Accounting Order establishing a variance account for the deemed short-term debt rate (DSTDR) related to the generic proceeding on cost of capital and other matters.

On October 31, 2024, the OEB issued a Letter and Accounting Orders establishing two variance accounts. One is the account regarding the return on equity (ROE) and the other is the account regarding deemed long-term debt rate (DLTDR), both related to the generic proceeding on cost of capital and other matters.

On March 27, 2025, the OEB issued its decision and order for the above-noted generic proceeding. The OEB addressed the variance accounts established by the above-noted Accounting Order and stated:

> *Utilities that implemented rates in 2025 using interim cost of capital parameters were granted variance accounts to record the difference between the revenue requirement at interim and final cost of capital parameters. The OEB will consider the disposition of these balances in both IRM and Custom IR update rate applications. The OEB will also consider applications to amend base rates to reflect any changes in revenue requirement for 2025, but only if there was no specific treatment previously approved by the OEB for the 2025 rate application. This approach will allow the variance accounts for 2025 to be disposed and closed.*
>
> *Any adjustment to base rates should use only data from the final approved revenue requirement calculation and billing determinants (no updated forecast).*

Per Ref 4, WPLP is using the sub-accounts Return on Equity Variance Account and Deemed short term Debt Rate Variance Account to capture the revenue requirement impact in 2025. Per Ref 5 and 6, OEB staff notes the continuity schedule of both accounts are missing.

Question(s):

a) Please confirm whether there is balance of these two accounts.

b) Please update the continuity schedule to include these two accounts activities/balance.

c) Please explain whether WPLP is planning to dispose of and close the variance accounts relating to the DSTDR and ROE in this application for 2026 revenue requirement.

d) If yes, please explain how the requirements of the OEB's March 27, 2025 decision and Accounting Orders have been addressed in the current application to dispose of these two variance accounts and confirm the accuracy of the balances in such variance accounts.

e) If no, please explain when WPLP plans to dispose of these variance accounts.

f) If no, please explain how WPLP plans to mitigate generating significant balances in the variance accounts and minimize intergenerational equity.

Response:

a) WPLP confirms there is a balance in these two accounts.

b) Given the continuity is supported by audited 2024 balances, WPLP has provided in Attachment 1 (filed as live Excel) a separate continuity with the 2025 forecasted principle additions and carrying charges for 2025 and 2026.

c) WPLP is not planning to dispose of the accounts in the 2026 rate application as the principle balance has not been audited.

d) Not Applicable.

e) WPLP will seek to dispose of the balance in the two variance accounts in the 2027 test year once the principle balance at the end of 2025 is audited.

f) WPLP will seek 1 year disposition of the account in 2027 to minimize intergenerational equity and minimize carrying charges on the account.

BOARD STAFF – 40

Reference: WPLP_APPL_2026 / H-1-1
WPLP_H-2-1-A_Continuity Tables for DVA_20250704
WPLP_H-1-1_Deferral and CWIP Continuity 2025_20250704

Preamble: In Reference 1, WPLP is seeking disposition of Account 1508-Federal CIAC Variance in this application. OEB staff noted that there is opening balance in Reference 2 while the account continuity schedule is missing in Reference 3.

Question(s):

a) Please include the complete continuity schedule of this account in Reference 3 and reconcile the amount to Reference 1 and Reference 2.

b) Please update/resubmit Reference 3.

Response:

a) Please see update continuity attached in response to Board Staff 36 (a) which includes continuity for Federal CIAC Variance Account.

b) Please see update continuity attached in response to Board Staff 36 (a) with updated Reference 3.

BOARD STAFF – 41

Reference: Exhibit H-2-2 / page 4 / Rows 14-16
Exhibit H-2-2 / page 5 / Para. 3
WPLP_H-2-1-A_Continuity Tables for DVA_20250704
WPLP_H-1-1_Deferral and CWIP Continuity 2025_20250704
Exhibit H-2-2 / page 7

Preamble: In Reference 1, OEB staff notes the method of recovery as capital or as expenses of the EPC COVID-Related Costs Deferral Account (EPC COVID Account) is not yet confirmed and the OEB prescribed rate is being used on an interim basis.

In Reference 2, WPLP states the amounts incurred in 2024 or later would be treated as capital and has recorded $82.1M principal and $1.8M interest as at December 31, 2024 in EPC COVID Account. It also states this conservative provisional amount associated with Valard's COVID-related cost overruns will be added to its rate base upon approval in a future application to trigger the additional CIAC under the Federal Funding Framework.

Question(s):

a) Please provide the rationality of why the amounts recorded ($82.1M and $1.8M) in EPC COVID Account would be treated as capital per Reference 2 if it is not yet confirmed per Reference 1.

b) Please confirm whether or not WPLP, in the current application, is proposing that the EPC COVID Account should be recovered as capital. If yes, please provide the rationale for this proposal. Otherwise, please confirm that the method of recovery – as capital or as expenses – will still be subject to determination in a future application.

c) Please resubmit both Reference 3 and Reference 4 to add EPC COVID Account continuity schedule which includes the balance as of December 31, 2024 and the forecasted carrying charges.

d) Please reconcile b) to Reference 2.

e) Please confirm the costs WPLP proposed to add to the future rate base in Reference 2 is $83.9M (82.1+1.8) as of December 31, 2024.

   i. If d) is not confirmed, please explain why not.

f) Please confirm that WPLP is planning to dispose EPC COVID Account in the next revenue requirement application. If not confirmed, please explain why not.

Response:

a) WPLP states in Exhibit H-2-2, page 5, paragraph 3 that any additional COVID amounts relating to 2020 arising from resolution of final EPC costs with Valard would be recorded in the EPC COVID Account, with the manner of disposition as an expense or as capital to be determined by OEB when WPLP is requesting disposition of the account. This is consistent with the wording in Reference 1.

b) WPLP is not seeking disposition of the EPC COVID Account within the 2026 rate application and will seek determination of the manner of disposition in a future rate application when seeking disposition of account.

c) Please see updated continuity attached to Board Staff 36 (a) with EPC COVID Account added to Reference 4 and response to Board Staff 38 (a) for update Reference 3 with EPC COVID Account.

d) As stated in Reference 2 and response to Board Staff 41(b), WPLP will seek determination of the manner of disposition for amounts recorded in the EPC COVID Account, as expense or capital, in a future proceeding when it seeks disposition of the account.

e) As stated above in response to Board Staff 41 (b), WPLP is not seeking to add any amount to rate base in 2026 from the account. WPLP will seek disposition of the EPC COVID Account, which would include the balance as at December 31, 2024 of $83.9 million. The determination of whether the EPC COVID Account balance should be recovered as expense or capital with be sought in a future proceeding.

f) Please see response to Board Staff 1 (b) and (d) for the planned timing of disposition of EPC COVID Account and expected timeline if arbitration is required.

BOARD STAFF – 42

Reference: Exhibit H-2-2 / Part A
Exhibit H-2-2 / page 6
Exhibit H-2-2 / page 6 / footnote 2

Preamble: In Reference 1, WPLP states that it executed an interim COVID cost change order for $90M which has not been recognized due to their remaining uncertainty given the status of the commercial discussions to date.

In Reference 2, WPLP states that it has recorded $82.1M principal and $1.8M interest as at December 31, 2024 in EPC COVID Account.

In Reference 3, WPLP states that the $82.1M is inclusive of the $90 million interim COVID cost change order less the value of EPC COVID cost accrual reversals on Testing, Quarantine and Vaccinations as result of a final change order ($7.9M) finalized in 2024.

OEB staff notes there is discrepancy between Reference 1 and Reference 2 that the $90M has not been recognized by WPLP while it was recorded in the EPC COVID Account.

Question(s):

a) Please confirm WPLP has recorded the interim COVID cost in EPC COVID Account mentioned in Reference 2.

   i. If confirmed, please explain the discrepancy identified by OEB staff.

   ii. If not confirmed, please explain why not.

b) Please provide the nature and breakdown of $7.9M final change order indicated in Reference 3. What were the specific activities or services for which these costs were incurred?

Response:

a) WPLP confirms the $82.1 million and $1.8 million interest have been recorded in the EPC COVID Account. The $82.1 million is inclusive of the executed interim change order of $90 million less $7.9 million in accrual reversals for amounts included within audited balances at the end of 2023. The accrual reversals related to change orders for

Testing, Quarantine, Vaccinations and COVID variable costs. There is no discrepancy as Reference 1 is referring to the costs in addition to the interim change order of $90 million that have not been recognized by WPLP given status of commercial discussions (see response to Board Staff 1).

b) The table below provides the finalized change order balances for Testing, Quarantine and Vaccinations

Change Orders	**Over Accrual ($000s)**	**Detail of Change Order**
Testing Equipment & Supplies	1,814	Change order related to labour and supplies related to COVID testing.
Vaccinations	6	Labour and incidental costs to provide vaccinations to project workers.
Quarantine Cost	1,624	Labour and incidental costs related to quarantining workers as required within the COVID Management Plan.
COVID Variable Cost[1]	4,500	A portion of the interim change order was accrued at the end of 2023, reducing the amount incurred in 2024. Further detail on COVID variable cost is provided in Exhibit H-2-2 page 3 of EB-2022-0149 filed rate application.
Total Over Accrual	**7,944**	

[1] This is not an executed change order but these costs were previously accrued in 2023 and are expected to be included as part of $90 million interim change order executed in 2024. To ensure its not double counted accrual was netted against EPC COVID Account.

BOARD STAFF – 43

Reference: Exhibit H-2-2 / Part C
WPLP_H-2-1-A_Continuity Tables for DVA_20250704
WPLP_H-1-1_Deferral and CWIP Continuity 2025_20250704

Preamble: WPLP is seeking disposition of forecasted carrying charges variance of a debit $24,381 for 2025 in this application and is proposing to close the account at the end of 2026.

Question(s):

a) Please resubmit both Reference 2 and Reference 3 to include the continuity schedule of CCCDA and reflect the disposition amount indicated in Reference 1.

Response:

a) Reference 2 continuity provided the disposition of carrying charges on the CCCDA for $24,381. The table has been provided below with a red box highlighting the amount. This table has been updated for OEB posted interest rates for Q3 and Q4 of 2025 and provided in response to Board Staff 38 (a). Reference 3 is at December 31, 2024, reflecting the 2024 audited balance and would not reflect the disposition amount of $24,381 as this amount takes into account forecasted recovery and carrying charges for 2025.

COVID Construction Cost Deferral Account - 2020	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26
Opening Principle Balance	4,349,913	3,987,420	3,624,928	3,262,435	2,899,942	2,537,449	2,174,957	1,812,464	1,449,971	1,087,478	724,985	362,493	0
Principle Recovery	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	- 362,493	-
Closing Principle Balance	3,987,420	3,624,928	3,262,435	2,899,942	2,537,449	2,174,957	1,812,464	1,449,971	1,087,478	724,985	362,493	0	0
OEB Interest Rate	3.64%	3.64%	3.64%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31
Opening Interest Balance	603,152	557,733	509,999	462,338	411,944	360,859	308,582	255,552	201,549	146,447	90,498	33,514	24,381
Interest Addition	13,448	11,134	11,206	8,473	7,783	6,590	5,837	4,864	3,766	2,919	1,883	973	0
Interest Recovery	- 58,868	- 58,868	- 58,868	- 58,868	- 58,868	- 58,868	- 58,868	- 58,868	- 58,868	- 58,868	- 58,868	- 58,868	2,032
Closing Interest Balance	557,733	509,999	462,338	411,944	360,859	308,582	255,552	201,549	146,447	90,498	33,514	- 24,381	- 22,349
2024 Audited Balance													
Principle	4,349,913												
Interest	603,152												
	4,953,065												
Per FS	4,953,066												
Variance	-												

BOARD STAFF – 44

Reference: Exhibit H-1-1 / Part A (6)
Exhibit H-2-1 / Part F

Preamble: In Reference 1, WPLP states that it is not seeking to add principal additions to the OM&A Variance Account in 2026 and requests that the account be continued until such time that it is able to dispose of its audited year-end 2025 balance, along with applicable carrying charges, in a future application.

In Reference 2, WPLP states that it will continue the account to record any variances between approved and actual OM&A expense along with applicable carrying charges for the 2025 and 2026 year as agreed in EB-2024-0176 but is not seeking to add to principal balance in 2026.

OEB staff observes that WPLP is going to dispose the account balance in the 2027 rate application (which will be WPLP's first multi-year revenue requirement application) for the December 2025 audited balance and will continue to record the principal balance for 2025 but not for 2026.

Question(s):

a) Please confirm OEB staff's observation.

   i. If confirmed, please explain why WPLP is not seeking to add principal balance for 2026.

   ii. If not confirmed, please clarify WPLP's proposal regarding recording principal balance in this account for 2025 and for 2026. Please provide rationale for the proposal.

Response:

a) Confirmed. WPLP is not seeking to continue to use the OM&A Variance Account for 2026 to capture under spend in 2026, and is therefore not planning to add principle amounts to the account balance in 2026. WPLP has outlined its budget process in its application and in response to Board Staff 25 (a), and as WPLP continues to obtain historical information on the operational requirements of the WPLP transmission system it expects to close the OM&A envelope gap between forecast and actuals.