REGIONAL INFRASTRUCTURE PLAN REPORT

Northwest Ontario

Regional Infrastructure Plan Report

[Northwest Ontario]

[Date: August 4, 2023]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Northwest Ontario Technical working group

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Disclaimer

This Regional Infrastructure Plan (RIP) Report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group (TWG).

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Technical Working Group.

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Executive Summary

REGION	Northwest Ontario Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: February 9, 2023 **END DATE:** August 4, 2023

1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the Northwest Region, preceded by, the publication of Needs Assessment (NA) report in July 2020 by Hydro One, followed by the Scoping Assessment (SA) in January 2021 & Integrated Regional Resource Plan (IRRP) in January 2023 published by the IESO respectively.

Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

2. OBJECTIVES AND SCOPE

Objectives:

- Provide a comprehensive summary of needs and wires plans to address the needs for the Northwest Ontario region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

Scope:

- A consolidated summary of needs and recommended plans for the region over a study period of 2023-2043 based on available information.
- A consolidated report of the needs and relevant wires plans to address near and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs and wires plans in the near and medium-term to address these needs based on new and/or updated information.

- Consideration of long-term needs identified in the Northwest Ontario IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of Regional Planning Process and their outcomes starting with the Needs Assessment, Scoping Assessment, Local Plan, Integrated Regional Resource Plan and finally details the Regional Infrastructure plan Methodology.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the Geographical boundaries, Circuit connections and Stations located in the Northwest Ontario region though a regional planning area map and a single line diagram. The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River, and Thunder Bay. The region is comprised of 230kV circuits from the Manitoba interties in the west to Marathon TS in the east and 115kV sub-systems in between.

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

This section provides a summary and brief description of all the projects completed in the past ten years or are currently underway.

I. Following Major projects were completed during the last ten years:

1. **Manitouwadge TS (2016)** – The 115/44kV, 5/7MVA T1 transformer was replaced with new 115/44kV 25/33/41.7 MVA unit.
2. **Dryden TS (2018)** – Five 115kV breakers and two 115/44kV, 11/15MVA transformers were replaced with new 115/44 kV 25/33/42MVA units.
3. **Lakehead TS (2017)** – Two 230/115kV autotransformers were replaced with new 230/115kV 150/200/250MVA units.
4. **Birch TS (2015)** – One 115/25kV transformer was replaced with a new 115/25kV 25/33/42MVA unit.
5. **Ear Falls TS (2022)** – Four 115kV breakers and one 115/13.2kV transformer was replaced with a new 115/13.2 kV 7.5/10/12.5MVA unit.
6. **East West Tie (2022)** – A 450 km, double-circuit, 230kV transmission line from Wawa TS to Lakehead TS was built with a connection approximately mid-way at Marathon TS.
7. **Wataynikaneyap Power Project Phase 1 (2022)** – A 300 km, single circuit, 230kV transmission line from Dinorwic to Pickle Lake, Ontario was built with a 230/115kV autotransformer, related switching facilities and necessary voltage control devices.

II. Following Major projects are underway:

1. **Rabbit Lake SS (2024-2027)** – Replace 115kV circuit breakers and associated equipment.
2. **Whitedog Falls SS (2025-2028)** – Replace 115kV circuit breakers and associated equipment.

3. **Mackenzie TS (2026-2029)** – Replace 230kV circuit breakers and associated equipment.
4. **Wawa TS (2026-2029)** – Replace two existing 230/115kV autotransformers with two new units; replace four 230kV and four 115kV circuit breakers.
5. **Wataynikaneyap Power Project Phase 2 (2022-2024 and beyond)** – Construct approximately 1438 km of 115kV, 44kV and 25kV transmission lines and twenty substations to connect 16 First Nations in two transmission subsystems.

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the load in the Northwest Ontario Region is expected to grow at an average annual rate of approximately 2% in winter from 2023 to 2033. The Region is winter peaking so this assessment is based on winter peak loads.

The following other assumptions are made in this report.

- The study period for the RIP assessments covers near and medium-term. However, a longer term forecast up to 2043 is provided to identify long-term needs and align with the Northwest Ontario region IRRPs.
- LDCs reconfirmed load forecasts up to 2033. A longer term forecast up to 2040 is adopted with IRRP load forecast. The additional three years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR); or winter 10-day LTR if undergoing a winter season analysis.
- Bulk transmission line and auto-transformation capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Northwest Ontario Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway are completed.

I. Needs identified in the region

a. Asset Renewal for Major HV Transmission Equipment (Replace equipment identified in deterioration and technical obsolescence)

- Rabbit Lake SS
- Whitedog Falls SS
- Mackenzie TS
- Wawa TS
- Marathon TS
- Lakehead TS
- Lakehead TS C8 Condenser
- Fort Frances TS
- Kenora TS

b. Station Capacity

- Margach DS
- Crilly DS
- White Dog DS
- White River DS
- Kenora MTS

c. Transmission Line Capacity

- E2R and E4D
- M2W

d. System Reliability, Operation and Load restoration

- Fort France MTS - Planned outages considering station single supply configuration
- E1C - Operation and High Voltage under a Normally-open configuration

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Northwest Ontario region. The needs include those previously identified in the NA and IRRP for the Northwest Ontario region as well as any new needs identified during the RIP phase.

9. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the Northwest Ontario region is given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Rabbit Lake SS	Replacement of the 115kV switchyard and its associated equipment	Hydro One Transmission	2024-2027	35.2
Whitedog Falls SS	Replacement of three 115kV breakers, DC station services and associated equipment	Hydro One Transmission	2025-2028	8.5
Mackenzie TS	Replacement of one 230/115kV autotransformer, five 230kV breakers, four switches, the AC station services and associated equipment	Hydro One Transmission	2025-2028	54.6
Wawa TS	Replacement of two 230/115kV autotransformer, associated breakers and equipment and station services	Hydro One Transmission	2026-2029	43.8
Marathon TS	Replacement of 230kV and 115kV breakers and associated equipment	Hydro One Transmission	2026-2029	14.6
Lakehead TS	Replacement of 230kV and 115kV breakers, the station services and associated equipment	Hydro One Transmission	2028-2031	41.5
Lakehead TS Condenser C8 Replacement	Replacement of the condenser C8 with a +60/- 40 MVAR STATCOM	Hydro One Transmission	2027	40.6
Fort Frances TS	Replacement of the 230kV breakers, associated equipment, and the station services	Hydro One Transmission	2029-2032	20.3
Kenora TS	Replacement of 230kV breakers, associated equipment, and the station services	Hydro One Transmission	2030-2033	17
Station Capacity Needs				
Margach DS	To be monitored and implemented in investment plan in 2025	Hydro One Distribution	2025	1

Crilly DS	To further assess the Alternative 1 and Alternative 2 from this RIP	Hydro One Distribution	NA	NA
White Dog DS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
White River DS	To be monitored and reviewed in the next planning cycle	Hydro One Distribution	NA	NA
Kenora MTS	To further assess the alternatives from this RIP; To be monitored and reviewed in next planning cycle	Synergy North	NA	NA
Transmission Line Capacity Needs				
E2R and E4D	To further evaluate the four alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	125-375
M2W	To further evaluate the two alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	TBD
System Reliability, Operation and Load restoration Needs				
Fort Frances MTS	Installation of a second breaker and switch in Fort Frances MTS to create a second supply to the MTS	Fort Frances Power	2026-2027	0.85
E1C Operation	To open E1C end at Ear Falls TS and installation of a 10 – 15 MVAR shunt reactor at Pickle Lake SS	Hydro One Transmission	2026-2027	20
Other Planning Considerations				
Fort Williams TS Shunt Capacitor Banks Replacement	Replacement of temporary capacitor banks with permanent units	Hydro One Transmission	2026-2027	6
Greenstone-Marathon Area System Needs	Further evaluation of the alternatives presented in the past IRRPs and RIP upon customers' requests	Hydro One Transmission and Proponent	TBD	TBD
Supply to the Ring of Fire	IESO to update Supply to the Ring of Fire study	IESO	TBD	TBD

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process where, Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The second cycle of the Regional Planning process for the Northwest Ontario Region was initiated with the publication of Needs Assessment (NA) report in July 2020 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in January 2021 and in January 2023 published by the IESO respectively.

The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

This report was prepared by the Northwest Ontario Technical Working Group ("TWG"), led by Hydro One Networks Inc. (Transmission). The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC"), the Municipalities, the transmitters, and the Independent Electricity System Operator ("IESO"). Participants of the TWG are listed below in Table 1.

Table 1: Northwest Ontario Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Networks Inc. (Distribution)
2	Independent Electricity System Operator ("IESO")
3	Atikokan Hydro Inc.
4	Fort Frances Power Corporation
5	Sioux Lookout Hydro Inc.
6	Synergy North
7	Wataynikaneyap Power LP
8	NextBridge Infrastructure LP
9	Hydro One Networks Inc. (Transmission)

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the Northwest Ontario Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the Northwest Ontario region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs and wires plans in the near and medium-term to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Northwest Ontario IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels look at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, Bulk System plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment (NA) which is led by the transmitter to identify, assess, and document which of the needs

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) that require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the Technical Working Group (TWG) as to whether further regional coordination is necessary to address some or all the regional needs. If no further regional coordination is required, recommendations to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the Independent Electricity System Operator (IESO) initiates the Scoping Assessment (SA) phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires or resource alternatives, e.g., Conservation and Demand Management (CDM), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), Integrated Regional Resource Plan (IRRP) and/or Regional Infrastructure Plan (RIP).

The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' CDM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and, development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in figure 1.

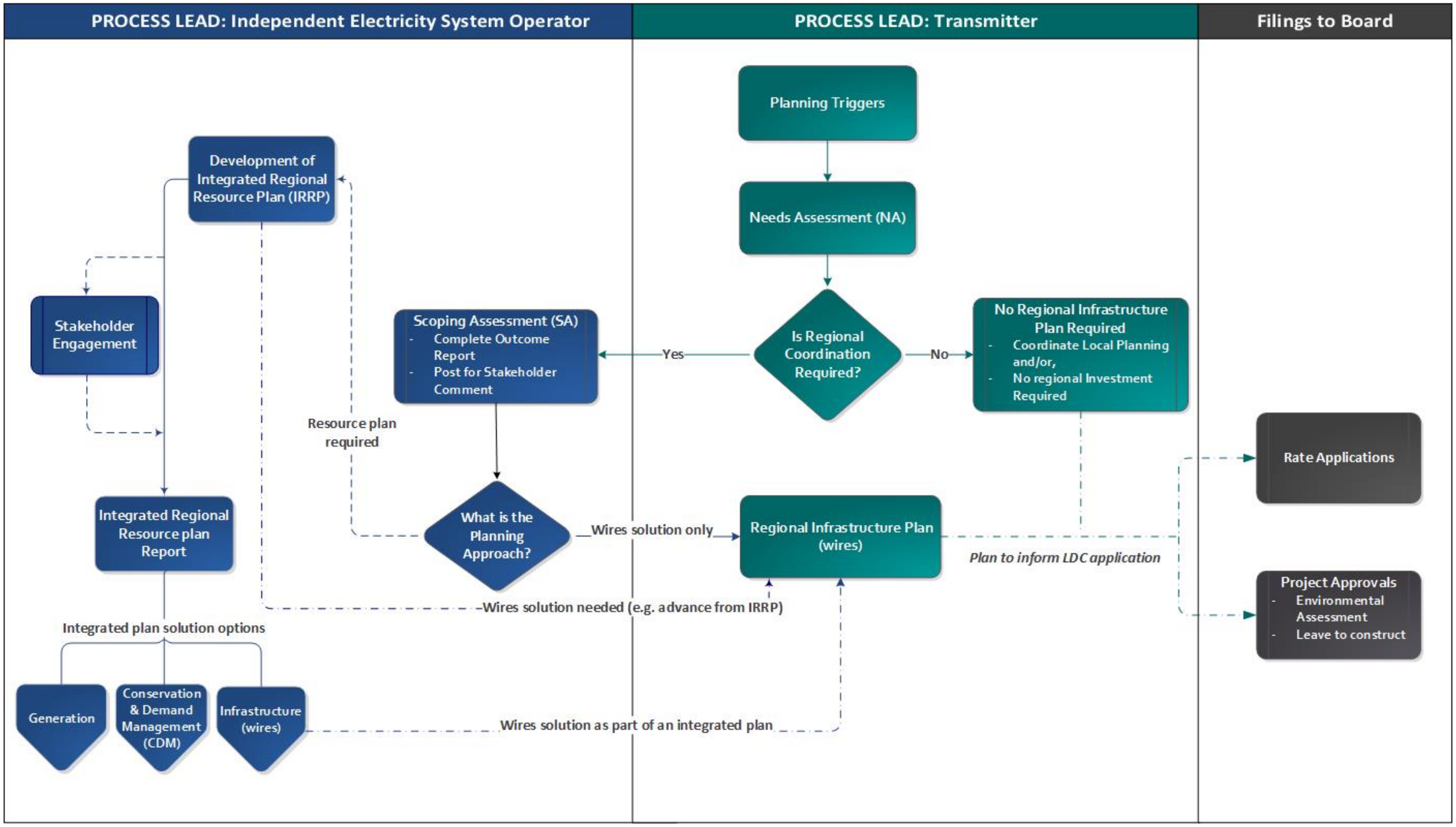

Figure 1: Regional Planning Process Flowchart

3.2 Regional Infrastructure Plan Methodology

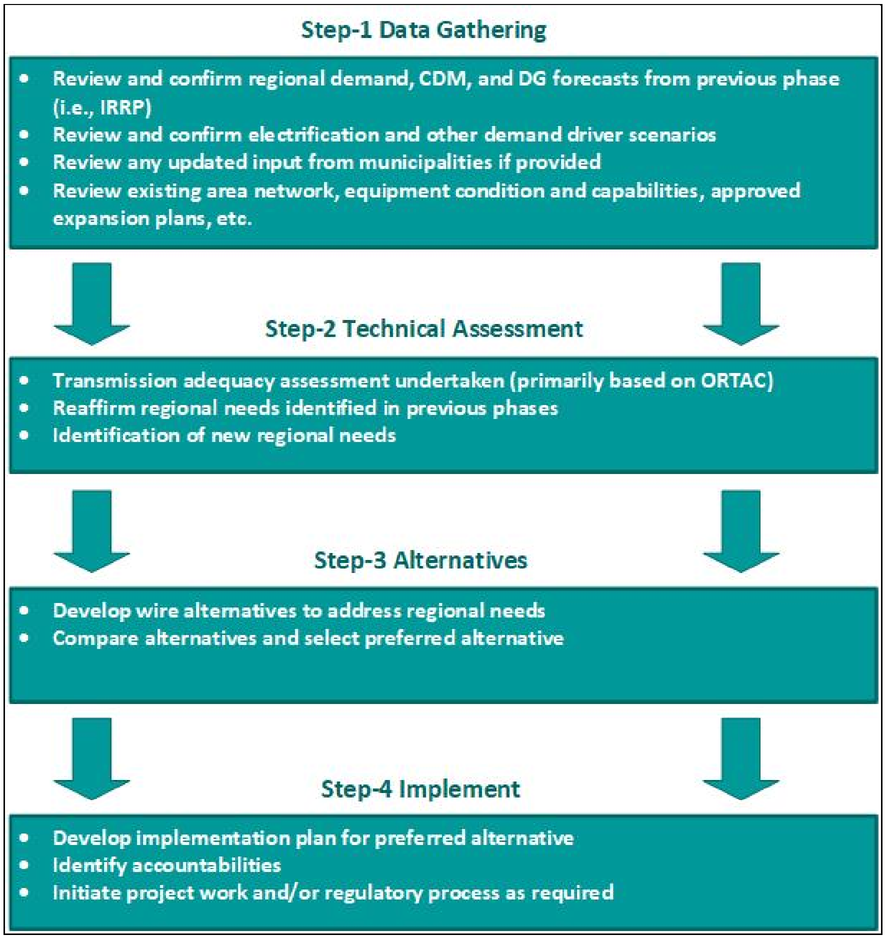

Figure 2: Regional Infrastructure Plan Methodology

Figure 2 above represents the four-step process of the Regional Infrastructure Plan which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:

- Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.

- Review and confirm electrification and other growth scenarios which effects the projects recommended in in previous stages and also update the inputs provided by the Municipalities.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and medium-term needs may be identified at this stage.

3.2.3. Alternative Development:

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

Northwest Ontario Region is roughly boarded by west of Hudson Bay and James Bay, North and West of the Lake Superior, and East of the Canadian province of Manitoba. The region consists of the districts of Thunder Bay, Kenora and Rainy River. Almost 54 percent of Region's entire population lives in Thunder Bay. The region accounts for approximately 60 percent of land area of the province and about two percent of Ontario's total population.

The geographical boundaries of the Northwest Ontario region are shown in Figure 3 below.

Figure 3: Map of Northwest Ontario Regional Planning Area

Bulk electrical supply to the Northwest Ontario region is provided through a combination of local generation stations connected to the 230kV and 115kV network, the East-West Tie transmission corridor and future Waasigan transmission line.

The Local Distribution Companies ("LDCs") that serve the electricity demands for the Northwest Ontario are Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Synergy North, Sioux Lookout Hydro Inc., and Fort Frances Power Corporation. The LDCs receive power at the step-down transformer stations and distribute it to the end users – industrial, commercial and residential customers.

In the first cycle of regional planning, the region was divided into four sub-regions, each with its own IRRP. The January 2015 Integrated Regional Integrated Regional Resource Plan ("IRRP") report for North of Dryden Sub-Region, the June 2016 IRRP report for Greenstone-Marathon Sub-Region, the July 2016 IRRP report for West of Thunder Bay Sub-Region, and the December 2016 IRRP report for Thunder Bay Sub-Region focused on northern, eastern, western, and central parts, respectively, of the Region. All IRRP reports were prepared by the IESO in conjunction with Hydro One and the LDCs. The January 2021 Northwest Region second cycle SA report prepared by IESO recommended a single IRRP covering the entire Northwest region. Subsequently, the January 2023 Northwest Ontario Region IRRP prepared by IESO considered the region as a whole.

4.1 North of Dryden Sub-Region

A radial single-circuit 115kV transmission line ("E4D") and a new 230kV transmission line ("W54W") supply electricity to the customers in the North of Dryden sub-region. The major supply stations for this sub-region are Dryden TS and Pickle Lake CTS, where the voltage is stepped down from the 230kV to 115kV at both stations, to serve local and industrial customers. Two of Wataynikaneyap Power's 115kV transmission lines (WBC and WPQ) will supply two remote subsystems, north of Pickle Lake and Red Lake. Electricity demand in the North of Dryden sub-region is generally supplied by local hydroelectric generation.

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the North of Dryden Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations
• E4D • E2R • E1C • M1M • M3E • C3W • C2M • WBC** • WPQ**	• W54W	• Red Lake TS • Cat Lake MTS • Pickle Lake CTS* • Slate Falls DS • Perrault Falls DS • Crow River DS • Pickle Lake SS • Ear Falls TS • CTS1 • CTS2 • CTS3*	• Ear Falls GS (18.6MW) • Manitou Falls GS (72MW) • Lac Seul GS (12.5MW)

*Stations with Autotransformers installed

** Multiple Wataynikaneyap Power circuits and transformer stations are supplied radially from WBC (which connects to Pickle Lake CTS) and WPQ (which connects to E2R). See Appendices B & C for details.

4.2 Greenstone-Marathon Sub-Region

Electrical supply to the customers in the Greenstone-Marathon Sub-Region comprises of Marathon TS and Alexander Switching Station ("SS"). Located in the town of Marathon, Marathon TS connects the Northwest electrical system to the East Lake Superior electrical system at Wawa TS, with four 230kV lines - W21M, W22M, W35M and W36M. Marathon TS steps down 230kV to 115kV and supplies customers in the Town of Marathon, White River and Manitouwadge through a 115kV single circuit - M2W. Three circuits A5A, A1B, and T1M - in series connect Marathon TS to Alexander SS in Thunder Bay Sub-Region.

The circuits and stations of the area are summarized in the Table 3 below:

Table 3: Transmission Station and Circuits in the Greenstone-Marathon Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations
• A1B • A5A • A4L • T1M • M2W	• W21M • W22M • W35M • W36M • M23L • M24L • M37L • M38L	• Marathon TS* • Longlac TS • Manitouwadge TS • Beardmore DS #2 • Jellicoe DS #3 • Manitouwadge DS #1 • Marathon DS • Pic DS • Schreiber Winnipeg DS • White River DS • CTS1 • CTS2 • CTS3 • CTS4 • CTS5	• CGS1 • CGS2 • CGS3 • CGS4 • CGS5 • CGS6

*Stations with Autotransformers installed

4.3 West of Thunder Bay Sub-Region

Supply to this Sub-Region is provided from a 230kV transmission system consisting of Kenora TS, Fort Frances TS, Dryden TS, and Mackenzie TS. Kenora TS steps down 230kV to 115kV and supplies customers in the City of Kenora and surrounding areas. In addition, it also connects Ontario to Manitoba's electrical system through two 230kV transmission lines, K21W and K22W. Fort Frances TS steps down 230kV to 115kV and supplies customers in the City of Fort Frances and surrounding areas. It also connects Ontario to Minnesota's electrical system through a 115kV transmission line, F3M. Dryden TS steps down 230kV to 115kV and supplies customers in the City of Dryden and surrounding areas. It also connects West of Thunder Bay to North of Dryden Sub-Region. Mackenzie TS steps down 230kV to 115kV and supplies customers in Atikokan and surrounding areas. It also connects West of Thunder Bay to the Thunder Bay Sub-Region. The West of Thunder Bay Sub-Region is also supplied by many local hydroelectric generation facilities.

The circuits and stations of the area are summarized in the Table 4 below:

Table 4:Transmission Station and Circuits in the West of Thunder Bay Sub-Region

115kV circuits	230kV circuits	Transformation Stations	Generation Stations

• A3M • M1S • B6M • M2D • 29M1 • D5D • K3D • 15M1 • K6F • K7K • F2B • F3M • F1B • K4W • K5W • SK1 • K2M • W3C	• A21L • A22L • K22W • K21W • K23D • K24F • W54W • D26A • F25A • N93A	• Kenora TS* • Fort Frances TS* • Dryden TS* • Mackenzie TS* • Moose Lake TS • Barwick TS • Fort Frances MTS • Kenora MTS • Agimak DS • Burleigh DS • Clearwater Bay DS • Eton DS • Keewatin DS • Margach DS • Minaki DS • Nestor Falls DS • Sam Lake DS • Sapawe DS • Shabaqua DS • Sioux Narrows DS • Valora DS • Vermilion Bay DS • CTS1 • CTS2 • CTS3 • CTS4 • CTS5 • CTS6 • CTS7	• Atikokan GS (227MW) • Whitedog Falls GS (64.8MW) • Caribou Falls GS (70MW) • CGS1 • CGS2 • CGS3 • CGS4 • CGS5 • CGS6

*Stations with Autotransformers installed

4.4 Thunder Bay Sub-Region

Thunder Bay Sub-Region consists of the Lakehead TS as the 230kV step-down transformation facility which steps down 230kV to 115kV and supplies customers in the City of Thunder Bay and surrounding areas. The area is served primarily at 115kV by three step-down transformer stations – Birch TS, Fort William TS, and

Port Arthur TS #1. Two parallel circuits A7L and A8L connect Lakehead TS to Alexander SS, which then interconnect Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS together.

The circuits and stations of the area are summarized in the Table 5 below:

Table 5: Transmission Station and Circuits in the Thunder Bay Sub-Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
• B5 • B9 • B14 • B15 • R2LB • R1LB • P7B • P3B • S1C • P5M • L3P • A6P • L4P • A7L • A8L	• A21L • A22L • M23L • M24L • M37L • M38L	• Lakehead TS* • Port Arthur TS #1 • Birch TS • Fort Williams TS • Murillo DS • Nipigon DS • Red Rock DS • CTS1 • CTS2 • CTS3	• Silver Falls GS (45MW) • Alexander GS (65.1MW) • Cameron Falls GS (70MW) • Pine Portage GS (143.9MW)

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of Northwest Ontario region is shown in Figure 4 below.

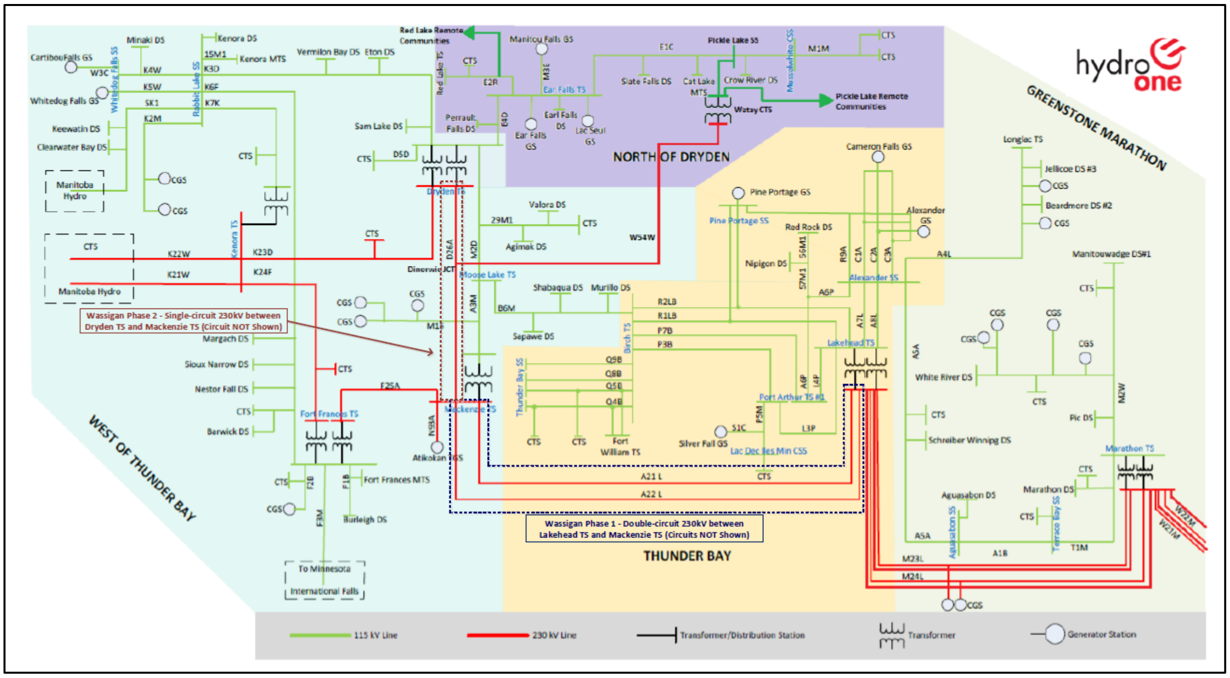

Figure 4: Northwest Ontario Transmission Single Line Diagram

4.5 New/Ongoing Transmission Line Projects Connect Sub-Regions

Below three recent/ongoing transmission projects in the Northwest regions reinforce the transmission corridors of the four sub-regions:

- East-West Tie Reinforcement
    - New double circuit 230kV line from Wawa TS to Lakehead TS in the Municipality of Shuniah, near Thunder Bay, Ontario, with a connection approximately mid-way at the Marathon TS.
- Waasigan Transmission Line Project
    - Phase 1 – New double circuit 230kV line from Lakehead TS to Mackenzie TS;
    - Phase 2 – New single circuit 230kV line from Mackenzie TS to Dryden TS.
- Wataynikaneyap Transmission Project
    - New single circuit 230kV line from Dinorwic Junction near Dryden to Pickle Lake CTS near Pickle Lake;
    - 115kV Remote connection subsystems north of Pickle Lake and Red Lake.

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section, all projects that have been completed in the past ten years or currently are underway is provided and their scope of work is briefly discussed. As a part of this or previous Regional Planning Cycle(s), several “Major HV Transmission Projects” were recommended in the Northwest Region to improve the supply capability and reliability.

Hydro One, Next Bridge Infrastructure and Wataynikaneyap Power, three Transmission Asset Owners (TAO) in the region have undertaken execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

- **Manitouwadge TS (2016)** – The 115/44kV, 5/7 MVA T1 transformer was replaced with new 115/44kV 25/33/41.7 MVA unit.
- **Dryden TS (2018)** –Two 115/44kV, 11/15 MVA transformers were replaced with new 25/33/42 MVA units in addition to replacement of five 115kV breakers.
- **Lakehead TS (2017)** – Two 230/115kV autotransformers were replaced with new 230/115kV 150/200/250MVA units.
- **Birch TS (2015)** – One 115/25kV transformer was replaced with a new 115/25kV 25/33/42MVA unit.
- **Ear Falls TS (2022)** – One 115/13.2 kV transformer was replaced with a new 115/13.2 kV 7.5/10/12.5MVA unit in addition to replacement of four 115kV breakers.
- **East West Tie Reinforcement (2022)** – A 450 km, double-circuit, 230kV transmission line from Wawa TS to Lakehead TS was built with a connection approximately mid-way at Marathon TS.
- **Wataynikaneyap Power Project Phase 1 (2022)** – A 300 km, single circuit, 230kV transmission line from Dinorwic to Pickle Lake, Ontario was built with a 230/115kV autotransformer, related switching facilities and the necessary voltage control devices.

II. Following Major projects are underway:

- **Rabbit Lake SS (2024-2027)** –This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace identified 115kV circuit breakers, associated disconnect switches, instrument transformers and equipment protections. The scope of work also involves installing new AC station service, DC battery and PCT building.
- **Whitedog Falls SS (2025-2028)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace identified 115kV circuit

breakers and associated switches. The scope of work also involves replacing and upgrading DC station supply system.

- **Mackenzie TS (2025-2028)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace 230kV circuit breakers, select protections, and AC/DC station service systems. A new 115/44kV load facility at Mackenzie TS to replace the one at Moose Lake TS.

- **Wawa TS (2026-2029)** – This investment will replace the station equipment identified as in poor condition and at high risk of failure. Hydro One will replace two autotransformers rated 75/100/125MVA, 230/115kV, four 230kV circuit breakers, and four 115kV circuit breakers. The scope of work also includes replacing associated disconnect switches, protection equipment and the station service system.

- **Wataynikaneyap Power Project Phase 2 (2022-2024 and beyond)** – This investment, led by Wataynikaneyap Power, will construct approximately 1438 km of overhead 115kV, 44kV and 25 kV transmission lines and twenty substations to connect 16 First Nations in two transmission subsystems by 2024 (10 north of Pickle Lake and 6 north of Red Lake). The Red Lake subsystem is designed to connect a seventh First Nation beyond 2024.

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

After verification from the TWG participants, and as no material changes were identified, the Northwest Region IRRP Load Forecasts were used in development of this Report. TWG participants, including representatives from LDC’s, Wataynikaneyap Power, IESO and Hydro One, provided information and input for the IRRP Load forecast, which also includes the inputs from the Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP).

During the study period, the load in the Northwest Ontario Region is expected to grow at an average annual rate of approximately 2% in winter from 2023-2033. The Region is winter peaking, so this assessment is based on winter peak loads.

Figure 5 shows the Northwest Region median winter weather net non-coincident load forecast from 2023-2033. Note that the non-coincident forecast is typically 10-15% higher than the coincident forecast in the Northwest region. This assessment is based on non-coincident forecast. In the event that non-coincident load forecast identifies network element needs, a sensitivity study will be performed utilizing coincident load forecast. The load forecasts from the Northwest Ontario Region were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

The main factor contributing to the deviation between the load forecasts in the IRRP and the RIP is the mining sector forecast. In the IRRP, the mining forecast was considered final as of the end of 2021. However, after the completion of IRRP, IESO has provided an updated reference scenario for the mining forecast, accounting for potential future mining projects. As a result, this updated mining forecast contributes to the variation between the load forecasts in the IRRP and RIP beyond 2026.

Non-coincident forecast for the individual stations in the region is available in Appendix A and is used to determine any need for station capacity relief in the region.

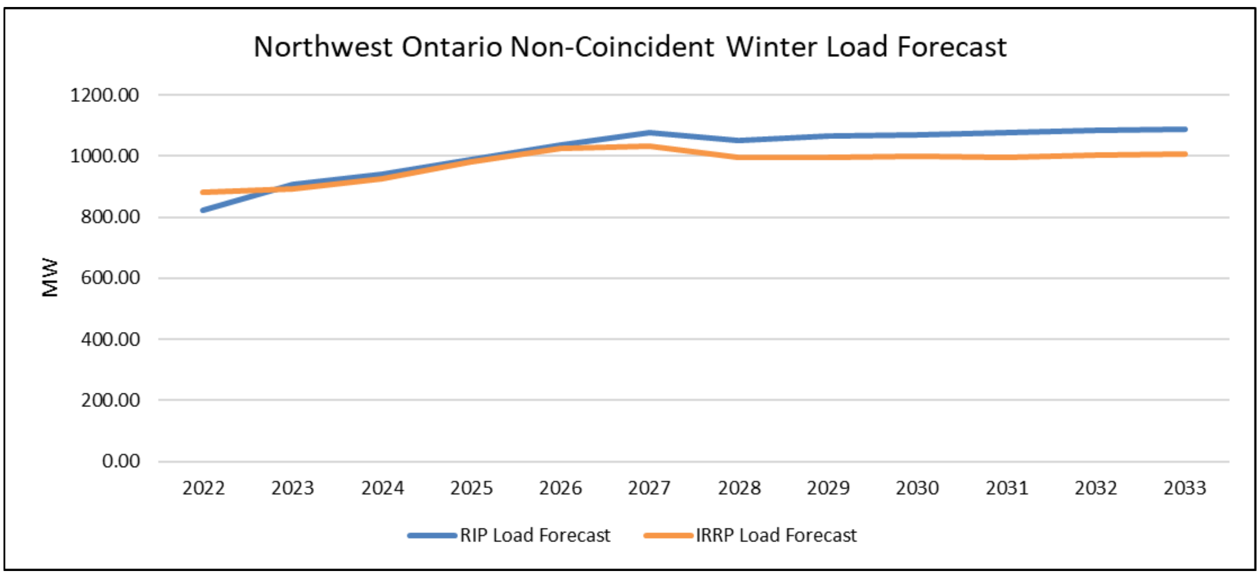

Figure 5: Northwest Ontario Region Winter Non-Coincident Net Peak Load Forecast

6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2033. However, a longer term forecast up to 2040 is provided to identify long-term needs and align with the Northwest region IRRPs.

- LDCs reconfirmed load forecasts up to 2033. A longer term forecast up to 2040 is adopted with IRRP load forecast. The additional three years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- This region is winter peaking, so this assessment is based on winter peak loads. However, since summer transmission line ratings are more constrained, Section 7.3 Transmission Line Capacity Needs is based on potential summer peak load demands.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) or by using the winter 10-day LTR if performing a winter season assessment.
- Bulk transmission line and auto-transformation capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the Northwest Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Northwest Region Second Cycle Needs Assessment Report completed in July 2020 by Hydro One
- Northwest Region Second Cycle Scoping Assessment Report completed in January 2021 by the IESO
- Northwest Region Second Cycle Integrated Regional Resource Plan Report completed in January 2023 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the Northwest Region. The complete list of major HV transmission equipment requiring replacement in the Northwest Region is provided in table 6 in this sub-section. Hydro One, Next Bridge Infrastructure and Wataynikaneyap Power are the Transmission Asset Owners (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
  replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 6: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD
Rabbit Lake SS	Replace equipment identified in deterioration and technical obsolescence	2024-2027
Whitedog Falls SS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2025-2028
Mackenzie TS	Replace equipment identified in deterioration and technical obsolescence	2025-2028
Wawa TS	Replace Equipment deterioration due to aging infrastructure	2026-2029
Marathon TS	Replace equipment identified in deterioration and technical obsolescence	2026-2029

Lakehead TS	Replace equipment identified in deterioration and technical obsolescence	2028-2031
Lakehead TS	Replace Condenser C8 identified in deterioration and technical obsolescence	2027
Fort Frances TS	Replace equipment identified in deterioration and technical obsolescence	2029-2032
Kenora TS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2030-2033

Note: The planned in-service year for the above projects is tentative and is subject to change.

7.2. Station Capacity Needs

Over the study period 2023-2033 RIP reviewed the capacity of all the 230kV, 115kV Transforming stations and 115kV step down Distribution stations within the Northwest Ontario Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 7 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (winter) Limited Time ratings.

Table 7: Northwest Ontario Region Station Capacity Needs in the study period

Sr.no.	Station Name	Capacity (MVA)	2023 Historical Loading (MW)	Station 10 day LTR (MW)	Need Date
1	Margach DS	11.60	10.07	10.44	2023
2	Crilly DS	2.40	2.28	2.16	2027
3	White Dog DS	3.20	2.37	2.88	2027
4	White River DS	15.60	12.02	14.04	2029
5	Sam Lake DS	24.00	23.34	21.06	Now
6	Kenora MTS	26.00	19.13	23.40	2030

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period 2023-2033 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Northwest Region. The NA and IRRP studies had previously indicated that the following Transmission lines potentially require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 8 below. The mining sector load materialization timing drives the need timeframe. It defines when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time ratings.

Table 8: Northwest Ontario Region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Contingency	LTE Line Rating (Amps)	Need Date
1	E2R	Ear Falls TS – Red Lake TS	NA	421	TBD
2	E4D	Dryden TS – Ear Falls TS	NA	410	TBD
3	M2W	Pic JCT – Manitouwadge JCT	NA	290	TBD

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operational and Load restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of loss of 2 transmission elements.

Furthermore, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

The IRRP studies had previously indicated that the following stations and transmission line require actions on system reliability and operational improvement. The RIP further confirms those needs with regards to System Reliability and Operation requirements.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility.

Table 9: Northwest Ontario Region System Reliability and Operational Needs in the study period

Station/Circuit	Need Description
Fort France MTS	Planned outages considering station single supply configuration
E1C	Operation and high voltage under a normally open configuration

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the Northwest Ontario region. These needs include those previously identified in the NA and IRRP for the Northwest Ontario as well as any new needs identified during the RIP phase. All references to costs included in the alternative analysis are considered as planning allowances[2] and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 10 below:

Table 10: Near/Mid-term Needs Identified in the region

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Asset Renewal Needs			
Rabbit Lake SS	Replace equipment identified in deterioration and technical obsolescence	2024-2027	8.1.1
Whitedog Falls SS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2025-2028	8.1.2
Mackenzie TS	Replace equipment identified in deterioration and technical obsolescence	2025-2028	8.1.3
Wawa TS	Replace Equipment deterioration due to aging infrastructure	2026-2029	8.1.4

[2] Allowances do not include real estate costs, environmental impacts and other costs not directly associated with the electrical infrastructure.

Marathon TS	Replace equipment identified in deterioration and technical obsolescence	2026-2029	8.1.5
Lakehead TS	Replace equipment identified in deterioration and technical obsolescence	2028-2031	8.1.6
Lakehead TS	Replace Condenser C8 identified in deterioration and technical obsolescence	2027	8.1.6
Fort Frances TS	Replace equipment identified in deterioration and technical obsolescence	2029-2032	8.1.7
Kenora TS	Replace equipment identified in deterioration, technical obsolescence and lack of spare parts availability and no manufacturer support	2030-2033	8.1.8
Station Capacity Needs			
Margach DS	Station Capacity Needs	2023	8.2.1
Crilly DS	Station Capacity Needs	2027	8.2.2
White Dog DS	Station Capacity Needs	2027	8.2.3
White River DS	Station Capacity Needs	2029	8.2.4
Sam Lake DS	Station Capacity Needs	Now	8.2.5
Kenora MTS	Station Capacity Needs	2030	8.2.6
Transmission Line Capacity Needs			
E2R	Capacity Needs of Section Ear Falls TS – Red Lake TS	TBD	8.3.1
E4D	Capacity Needs of Section Dryden TS – Ear Falls TS	TBD	8.3.1
M2W	Capacity Needs of Section Pic JCT – Manitouwadge JCT	TBD	8.3.2
System Reliability, Operational and Load restoration Needs			
Fort France MTS	The planned transmission outage caused customer interruptions due to the station's single supply configuration.	2023	8.4.1
E1C Operation and High Voltage	Supply capacity limitations with E1C operated normally closed; high voltage issues with E1C operated normally open	2023	8.4.2

Other Planning Considerations			
Fort William TS Shunt Capacitor Banks Replacement	Temporary capacitor banks to be replaced with permanent units	2026-2027	8.5.1

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for “right sizing” the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One’s perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

8.1.1. Rabbit Lake SS

Rabbit Lake SS, a North American Electric Reliability Corporation (NERC) Bulk Electrical System station, was originally built in 1956 and is located within the city limits of Kenora, Ontario. The switching station has six 115kV transmission lines connecting to three customer generating stations (CGSs) as well as Whitedog Falls SS, Kenora TS, Fort Frances TS, Dryden TS, and the interconnection with Manitoba Hydro. There are six 115kV oil circuit breakers and two 115kV SF6 circuit breakers in the yard.

Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence due to outdated design. The scope of work involves replacing 115kV circuit breakers, associated disconnect switches, instrument transformers and equipment protections. A New AC station service, DC battery and PCT building will also be installed.

This investment will help maintain the reliability of supply to area customers and reduce the risk of interruptions caused by station equipment failure. The project is currently planned to be completed in 2024-2027.

8.1.2. Whitedog Falls SS

Whitedog Falls Switching Station (SS) located approximately 80 km northwest of the City of Kenora, containing three 115kV circuits that terminate at the station with four circuit breakers, connecting to Rabbit Lake SS, Caribou Falls GS, and Whitedog Falls GS.

Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence with little or no spare parts and manufacturer support. The scope of work involves replacing 115kV circuit breakers and associated disconnect switches. Replacement and upgrades of the DC station supply system will also be part of this investment,

This investment will help maintain the reliability of supply to area customers and reduce the risk of interruptions caused by station equipment failure. The project is currently planned to be completed in 2025-2028.

8.1.3. Mackenzie TS

Mackenzie TS is a 230/115kV station is located approximately 200 km west of Thunder Bay, Ontario. Mackenzie TS has six 230kV breakers which are about 46 years old. The station is a major station for Waasigan transmission line reinforcement project.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure and technical obsolescence with minimal spare parts and manufacturer support. The scope of work involves replacing the existing 230/115kV 75/125 MVA autotransformer with new 230/115kV 75/100/125 MVA. The project will also replace 230kV circuit breakers, select protections, and AC/DC station service systems. Hydro One has also planned to install a new 115/44 kV load facility at the station to replace the one at Moose Lake TS, optimizing the area supply configuration.

This investment will help maintain the reliability of supply to Atikokan Hydro customers and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2025-2028.

8.1.4. Wawa TS

Wawa TS is a 230/115kV transformer station, located southeast of the township of Wawa in northern Ontario. It was put in-service in 1969. The station is a major hub for connecting the Northeast, Northwest and Hydro One Sault Ste. Marie transmission systems. The existing autotransformers, oil circuit breakers, disconnect switches, protection and control, station service, and other ancillary facilities are in poor condition and in deterioration that require replacement to maintain the operability and reliability of the station.

Hydro One has plans to replace all deteriorated equipment at the station. The scope of work involves replacing two 239-121/13.9kV 75/100/125 MVA autotransformers, four 230kV circuit breakers, and four 115kV circuit breakers. In addition, the scope of work also includes replacing associated disconnect switches, protection equipment and station service system.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2026-2029.

8.1.5. Marathon TS

Marathon TS is a 230/115kV transformer station, located in the City of Marathon in northern Ontario. It was put in-service in 1970. The station is critical to the transmission system of the Northwest and a major hub for East-West power transfer. All four 115kV oil circuit breakers at the station are about 40 years old, and three 230kV circuit breaker at the station are about 48 years old.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure to ensure the reliability of the transmission system and supply to customers. The scope of work involves replacing three 230kV circuit breakers with new SF6 breakers, and four 115kV circuit breakers with new SF6 breakers. The replacement of disconnect switches, protection equipment, and AC station service system will also be part of this investment.

In addition to component replacement. this project will separate and re-terminate two branches of 115kV circuit M2W. M2W is a radial transmission line consisting of two independent branches that merge into 1 switching position at the entry point of Marathon TS. To unbundle, Hydro One will install one additional 115kV circuit breaker with associated protections in order to create a new switching position at Marathon TS 115kV bus.

This investment at Marathon TS will improve transmission system reliability performance and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2026-2029.

8.1.6. Lakehead TS

Lakehead TS is a 230/115kV transformer station which was put in-service in 1955, located northeast of the city of Thunder Bay in norther Ontario. The station is critical to the transmission system of the Northwest, a major hub for East-West power transfer, and a major station for Waasigan transmission line reinforcement project. The station is classified as Bulk Electric System (BES) under NERC standards.

8.1.6.1 HV Component Replacement

Hydro One has plans to replace all station equipment identified in deterioration due to aging infrastructure to ensure the reliability of the transmission system and supply to the customers. The scope of work involves replacing high voltage circuit breakers with new SF6 breakers, replacing eight 115kV circuit breakers with new SF6 breakers, replacing protection equipment associated with 115kV facilities and the synchronous condenser, replacing select switches, and replacing/upgrading AC station service system.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2028-2031.

8.1.6.1 Condenser C8 Replacement

The transformers T7 and T8 at Lakehead TS are 239/121/13.9 kV 250 MVA autotransformers with primary and secondary windings connecting to the 230kV and 115kV systems, respectively. The tertiary windings of T7 and T8 are rated at 60MVA. In 2009, a -40/+60Mvar SVC replaced a poor condition condenser connected at T7 tertiary bus. The SVC consists of a 100Mvar TCR and a 60Mvar filter. A recent condition assessment has highlighted the poor condition and high risk of failure associated with C8, a synchronous condenser connected to T8's tertiary bus. To address this issue, Hydro One consulted with IESO to explore the options of maintaining the status quo, removing the condenser, or replacing it with appropriately sized equipment. The consideration of the need for condenser inertia was also part of the assessment.

Following discussions between IESO and Hydro One, it has been recognized that replacing C8 with a static synchronous compensator (STATCOM) is the preferred solution. To ensure optimal controller coordination, the recommended replacement strategy involves sourcing the STATCOM from the same vendor as the existing SVC. By installing a STATCOM with the same capacity and connecting it to the 13.8kV tertiary winding of transformer T8, effective voltage control of the 230kV bus at Lakehead can be achieved in coordination with the existing SVC at T7. This asset and infrastructure replacement will effectively mitigate the risks associated with equipment failure and enhance the overall reliability of the system. It's important to note that IESO is currently conducting further studies to assess the reactive power needs in northern Ontario.

8.1.7. Fort Frances TS

Fort Frances TS is in the Town of Fort Frances and was put in-service in 1947. Hydro One has plans to replace equipment identified in deterioration due to aging infrastructure and technical obsolescence. The scope of work involves replacing high voltage circuit breakers, replacing/upgrading AC/DC station service systems and protection equipment.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2029-2032.

8.1.8. Kenora TS

Kenora TS is a 230/115kV station in-service since 1972 and located in east side of Kenora City, Ontario. The station is critical to supply of the city of Kenora and the interconnection with the province of Manitoba.

Hydro One has plans to replace station equipment identified in deterioration due to aging infrastructure and technical obsolescence with minimal spare parts and manufacturer support. The scope of work involves replacing high voltage circuit breakers, protection equipment and replacing/upgrading AC/DC station service systems.

This investment will improve transmission system reliability and reduce the risk of interruptions caused by station equipment failure. This project is currently planned to be completed in 2030-2033.

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2023-2033 for the 230kV ,115kV Transformer stations and 115kV step down Distribution stations in the Northwest Ontario Region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following Station capacity needs have been identified in the during the study period:

8.2.1 Margach DS– 115kV – Distribution Station Step-Down Transformer Capacity Needs (2023)

Margach DS is approximately 10 km east of Kenora. Margach DS presently has two 115/ 26.5kV 7.5MVA transformers (T1/T2) with a winter LTR of 10.4MW. The historical demand at Margach DS has remained stable, consistently just below 10 MW. The station will exceed its normal supply capacity in 2023.

Table 11: Margach DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Margach DS	10.4	10.50	10.48	10.47	10.48	10.51	10.53	10.53	10.53	10.55	10.55	10.58

The following alternatives were considered to address Margach DS capacity need.

Alternative 1: Install Transformer Fan Monitoring.

Installing transformer fan monitoring is a relatively inexpensive solution to increase the station LTR by enabling the use of higher thermal ratings on the existing transformers.

Alternative 2: Maintain Status Quo

Considering that the peak loading in 2022 was 9.96 MW and there is only anticipated natural residential load growth, maintaining the status quo is also considered a viable solution.

The LDC- Hydro One Distribution recommends alternative 2 as the preferred solution at the time of this RIP. Regarding alternative 1, the LDC has incorporated it into its investment plan with an anticipated implementation date in 2025. Given the gradual growth in station loading and the existing plan in place, the LDC will closely monitor the station's load and take necessary actions if required before 2025, ensuring a smooth transition to Alternative 1.

8.2.2 Crilly DS– 115kV – Distribution Station Step-Down Transformer Capacity Needs (2027)

Crilly DS is a small (~2.2 MW LTR) station supplied from 115kV transmission circuit M1S and has a 6.6 kV bus shared with Sturgeon Falls CGS, a small hydroelectric plant located approximately 50 km west of Atikokan. This legacy non-standard supply arrangement results in annual outages at Crilly DS during maintenance periods of the generator. Backup power from diesel generation is utilized when Sturgeon Falls is offline. Moreover, the station equipment is approaching its end-of-life, and limited space constraints limit refurbishment options on-site.

Crilly DS is expected to exceed its capacity in 2027 due to incremental growth in the community.

Table 12: Crilly DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Crilly DS	2.16	2.14	2.14	2.15	2.16	2.18	2.19	2.20	2.21	2.23	2.24	2.25

To address this capacity issue, the TWG has identified the following alternatives for consideration:

Alternative 1: Refurbish Crilly DS at the current location

This alternative is likely the least costly solution, but Crilly DS will still rely on backup power from diesel generation during outages at Sturgeon Falls CGS.

Alternative 2: Rebuild Crilly DS at a different location as a 115/25 kV HVDS

This alternative entails rebuilding Crilly DS at a different location, operating as a 115/25 kV HVDS station. The new site would be situated closer to the existing station and supplied by the 115kV transmission circuit M1S.

Alternative 3: Rebuild Crilly DS at a different location as a 230/25 kV TS (connected to F25A closer to the community served by Crilly DS)

This alternative will rebuild the station and operate it as a 230/25kV Transformer Station (TS).

Alternative 4: Replace Crilly DS with 115:25kV padmount transformer (transformer enclosed in a grounded cabinet that can be accommodated outside the existing station fence)

This alternative requires further investigations on the feasibility of configuring the station with a padmount transformer.

Hydro One Distribution are considering all 4 alternatives. Due to the radial supply nature of M1S, reliability concerns can only be partially addressed by upgrading station assets at Crilly DS. Considering the timeline and the need for further assessment, the LDC has indicated that additional studies and investigations are required to evaluate the cost and benefits of all four alternatives before determining the preferred solution to address the station capacity needs projected for 2027. In the interim, the LDC will closely monitor the loading of Crilly DS and take appropriate actions if the load grows faster than forecasted. This proactive approach will ensure that any capacity challenges are promptly addressed. By conducting thorough analyses and closely managing the station's loading, the LDC aims to make informed decisions and select the most suitable alternative to meet the future capacity requirements of Crilly DS.

8.2.3 Whitedog DS – 115kV - Distribution Station Step Down Transformer Capacity Need (2027)

Whitedog DS is a distribution station that receives its supply from the OPG Whitedog GS 13.8kV bus. The station is comprised of three 0.667MVA single-phase transformers, with an additional single-phase transformer serving as a spare. All the single-phase transformers in the station are 75 years old. Currently, Whitedog DS is connected to a single feeder (12.48kV) that supplies the Whitedog First Nation community.

Whitedog DS is expected to exceed its capacity in 2027 due to incremental growth in the community. Recently, the Whitedog First Nation also expressed plans for growth and expansion within their community and it is at the preliminary stage of development. To support this potential load growth, the capacity of the Whitedog DS station would need to be increased. In addition, OPG is planning system renewal work on this 13.8 kV bus and needs to coordinate scope and cost with the LDC if the connection is to be maintained.

Table 13: Whitedog DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Whitedog DS	2.88	2.80	2.82	2.85	2.87	2.92	2.95	2.99	3.01	3.05	3.07	3.11

To address this capacity issue, the TWG has identified the following tentative alternatives for consideration:

Alternative 1: Replace the existing transformers with a larger size

This alternative will allow Whitedog DS to remain connected to the OPG bus. But it involves expanding the existing site to accommodate larger-size transformers, which need OPG's approval since OPG owns the land. Additionally, OPG is in the process of refurbishing the Whitedog GS switchgear; if the DS is to remain connected to OPG, the scope of work is subject to coordination with OPG.

Alternative 2: Relocate Whitedog DS as a 115/12.48 kV DS

This alternative will relocate Whitedog DS with a larger size transformer to the Hydro One Whitedog Switching Station, connecting it to the transmission 115kV bus. This solution may require a small site expansion, which would necessitate approval from OPG.

Alternative 3: Maintain Status Quo

This alternative will not take action at this point and continue monitoring if the forecasted load growth materializes. This alternative requires the LDC to work with the generator to land on an amicable solution for the generator's system renewal work.

The LDC – Hydro One Distribution recommends alternative 3 maintaining the status quo for now. While the Whitedog First Nation has expressed plans for future growth, they are currently in the preliminary stage, indicating that the load demand increase might not materialize in the immediate future. Maintaining the status quo allows the LDC to closely monitor the actual load growth and assess its sustainability before committing to significant infrastructure changes. If the projected increase materializes, appropriate corrective actions will be taken. This approach ensures that the LDC can respond effectively to the evolving needs of the Whitedog First Nation while maintaining a reliable power supply to the community.

8.2.4 White River DS – 115kV - Distribution Station Step Down Transformer Capacity Need (2029)

White River DS is a 115/26.8 kV step down distribution station supplying the Town of White River. The station has two 7.5/10MVA transformers both in service serving the load with a LTR of 14.04MW. However, the station is lacking the provision of a spare transformer as a backup in the event of a failure. Currently, if one of the transformers fails, the load can be transferred to the remaining operational unit. With the projected load growth, White River DS's contingency capacity to fully restore the load following a contingency will be compromised, specifically, in the event of one transformer failure, the failed transformer's load cannot be offloaded to the other transformer at the station due to overloading as the load grows in the area. Hence, the station is expected to exceed the contingency capacity in 2029.

Table 14: White River DS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
White River DS	14.04	13.42	13.51	13.69	13.80	13.91	14.00	14.09	14.18	14.27	14.35	14.44

To address this capacity issue, the TWG has identified the following tentative alternatives for consideration:

Alternative 1: Maintain Status Quo

This alternative will not take action at this point and continue monitoring if the forecasted load growth materializes.

Alternative 2: Install a MUS Facility

There is a tentative plan for the LDC to look into installing a MUS facility at the station; in such case, the station contingency capacity can be increased with the additional MUS facility. It is also recognized as the most cost-effective solution to address the need.

The LDC – Hydro One Distribution recommends alternative 1 to maintain the status quo as the preferred solution. Based on the load forecasts, White River DS will exceed contingency capacity in 2029. The next cycle of regional planning will commence in 2025. It will allow the working group to reevaluate this need and confirm if the capacity needs at White River DS still holds in 2028. Should this be the case, the study group at that moment will decide the best course of action to fill this need.

8.2.5 Sam Lake DS – 115kV -Distribution Station Step Down Transformer Capacity Need (Now)

Sam Lake DS is a Hydro One Distribution owned 115/25kV High Voltage Distribution Station (HVDS) supplied from 115kV circuit K3D. The station is the sole supply for Sioux Lookout Hydro LDC. It contains two 115kV/25kV 15/20/25MVA transformers (T1 and T2) and only one of the transformers is in-service at any given time. The station is projected to exceed its normal supply capacity this year. A Local planning study[3]was conducted and was published in January 2023 with a TWG[4] recommended solution to address the need.

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Sam Lake DS	21.6	28.22	28.47	28.67	28.70	28.72	28.74	28.74	28.74	28.78	28.81	28.87

The following alternatives were considered by the TWG in the Local Planning study:

Alternative 1 – T1 and T2 Transformer both in service at Sam Lake DS

Currently, only one of the transformers is on load, while the other is a hot spare in case of a transformer contingency. Therefore, the additional capacity can be made available if both T1 and T2 are in service.

Alternative 2 – Install fan monitoring on T1 and T2 at Sam Lake DS

As discussed in section 2, T1 and T2 transformers at Sam Lake DS are currently equipped with unmonitored fans, and it is not reliable to load the transformers at the maximum fan-cooled rating without a fan monitoring system. Therefore, installing fan monitoring can increase the station capacity at Sam Lake DS.

Alternative 3 – Install an additional (3rd) transformer at Sam Lake DS

An additional transformer at Sam Lake DS can also increase the capacity at Sam Lake DS.

Alternative 4 – Construct a new 115kV/25kV station supplied from Hydro One's K3D Circuit

A new High Voltage Distribution Station (HVDS) can be built to increase the capacity of the area.

Alternative 5 – Construct a new 230kV/25kV station supplied from Wataynikaneyap transmission system

[3] Local Planning – Report (Sam Lake DS)

[4] Local Planning Technical Working Group Members: Hydro One Inc. (Transmission), Hydro One Inc. (Distribution) and Sioux Lookout Hydro.

A new station can be built and supplied from the new Wataynikaneyap 230kV system, which would bring in a new transmission supply and significantly improve the load supply diversity at the Sam Lake DS area in case of a K3D outage.

The TWG have conducted a coordinated review and evaluation of all the alternatives to address the local capacity need. The TWG recommended Alternative 2 – Install fan monitoring on T1 and T2 at Sam Lake DS. This alternative allows Hydro One Distribution and Sioux Lookout Hydro to address the capacity need in the timeframe required (based on the winter conservative load forecast) and maintain supply reliability to the Sam Lake area customers. This alternative is the lowest cost option and achieves the best balance between cost versus local system benefits.

8.2.6 Kenora MTS – 115kV - Transmission Station Capacity Need (2030)

Kenora MTS is currently equipped with 115/12.5 KV transformers T1, T2 and T4. T1 and T4 have a rating of 9/12 MVA, while T2 has a rating of 10/13/14 MVA. The station's total planning winter LTR is 23.4MW. Therefore, this station will exceed its normal supply capacity in 2030.

Table 15: Kenora MTS Load Forecast

Station	LTR (MW)	Load Forecast (MW)										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Kenora MTS	23.4	21.4	21.7	21.9	22.1	22.5	22.9	23.2	23.5	23.8	24.1	24.4

Synergy North has received inquiries from potential customers seeking new connections, but formal agreements still need to be finalized. Although these new connection loads have not been incorporated into the forecast, an annual growth rate of 1.25% has been applied to account for the significant level of development interest. The following wires and non-wires alternative solutions are considered:

Alternative 1: Expand Kenora MTS with an Additional Transformer

Install an additional transformer and associated protections, control, and structures with an expansion of the existing station.

Alternative 2: Construct a new substation across the city from the existing station

The proposed new substation will be located on the city's west side. In addition to increasing the supply capacity, this solution will provide substantial distribution system benefits by reducing the feeder length required to reach the customers and improving the distribution system performance.

Alternative 3: Non-Wires Solutions

IRRP recommends three non-wire alternatives. A 4MW gas generation facility, a 6-hour 4MW (24MWh) battery, or a combination of energy efficiency measures and demand response are feasible options. This alternative will provide potential distribution benefits to the end customers.

Alternative 4: Maintain Status Quo

This alternative is considered based on the long-term horizon of the need. Kenora MTS will exceed station capacity in 2030 based on the load forecasts provided by the LDC. The next cycle of regional planning will commence in 2025 and will allow the working group to reevaluate this need and confirm if the station capacity need still holds true in 2028. Should this be the case, the TWG at that moment will decide the best course of actions to address this need.

The TWG recommends Alternative 4 as the preferred solution at this RIP. Considering the long-term outlook of the need, the LDC intends to move forward by retaining the services of a consultant to assist in understanding the pricing of each of the proposed alternatives. Prior to determining the preferred alternative an investigation of the total costs and benefits of each solution will be completed. The LDC does not intend to engage in any material investments prior to 2028 to mitigate the challenge of Kenora MTS reaching its thermal capacity, instead continued study and monitoring of load growth and customer connections is anticipated to trigger investment. To fully understand the preferred alternative and investment benefits, the LDC intends to incorporate and quantify the benefits of grid scale and behind-the-meter (BTM) energy storage solutions that may allow for access to many different services reducing the cost of reliable service to the City of Kenora.

Furthermore, the LDC recognizes that non-wires alternative could be developed in stages to reduce cost and align with the load growth as compared to a traditional wires investment (e.g., new substation.) This offers enhanced reliability for radially supplied customers that would otherwise not have effective options to improve their reliability, particularly for momentary outages.

The roadmap below has been prepared to ensure that the LDC remains well positioned to address the challenge with sufficient time for deployment and with the most cost-effective solution for its customers.

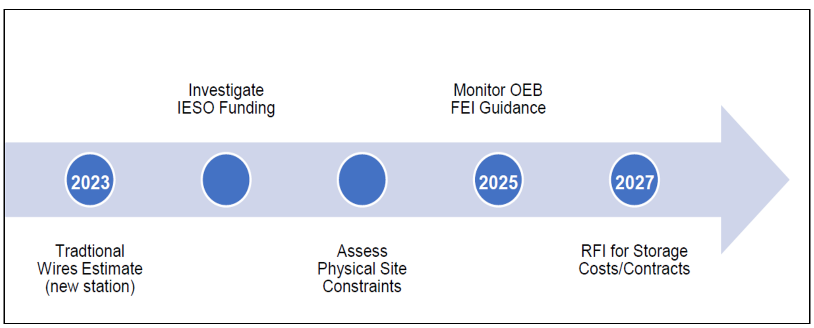

Figure 6: Kenora MTS Strategy Roadmap

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission

Lines Capacity Assessment was performed over the study period 2023-2033 for the 230kV and 115kV Transmission line circuits in the Northwest Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the Northwest region currently does not have a firm supply capacity need. But it is important to consider the potential impact of large mining and industrial developments that can quickly consume the remaining supply capacity with minimal lead time. After engaging with development proponents and stakeholders during the IRRP phase, the Technical Working Group (TWG) identified three potential transmission circuits, E4D, M2W and E2R, that may require additional supply capacity if all proposed projects materialize.

8.3.1 E4D and E2R – 115kV – Capacity Needs under Mining Sector Development

The E4D circuit supplies the Ear Falls and Red Lake area, while the E2R circuit serves the Red Lake area north of Dryden. The E4D circuit has a continuous summer rating of 410 A, equivalent to approximately 72 MW. Additionally, there is a combined 18 MW of dependable hydro generation output from three hydroelectric power stations. Considering the thermal capability and hydro generation, the load capability of the E4D circuit is approximately 90 MW during the summer. It is worth noting that the winter load meeting capability is expected to be higher due to the circuit's higher thermal rating and increased hydro generation output.

As for the E2R circuit, it has a continuous summer rating of 421 A, translating to a load meeting capability of approximately 74 MW. The E2R circuit's continuous winter rating is 528 A, resulting in a load meeting capability of approximately 93 MW due to pre-contingency thermal and voltage limitations, meaning a load of 93 MW also causes pre-contingency voltage declines at Red Lake TS.

The IRRP forecasts the summer peak demand of the E4D circuit to reach 67 MW in 2032, and the summer peak demand of the E2R circuit to reach 61 MW in the same year.

The system area map is shown below in Figure 7:

Figure 7: Dryden - Ear Falls - Red Lake Map

Considering the potential combined area load growth from mining and Wataynikaneyap Power customer connections, which could increase by 50-115 MW by 2028, a few mining and industrial customers are actively engaging with IESO and Hydro One Transmission to explore potential options to accommodate this load increase. As shown on Figures 8-11, four transmission alternatives have been proposed to address the capacity needs in the area. These options also require the installation of appropriately sized voltage devices to mitigate voltage performance criteria.

- Alternative 1 - Upgrade 115kV Circuit E4D and E2R:

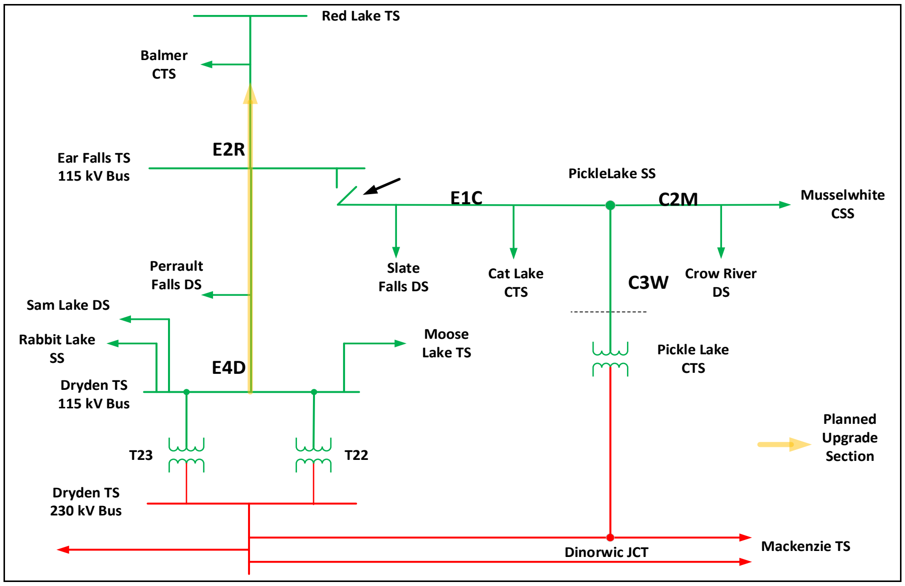

Figure 8: Alternative 1 Single Line Diagram - Upgrades on Existing Infrastructure

- Alternative 2 – Building a new 115kV Single Transmission Line from Dryden TS to Red Lake TS:

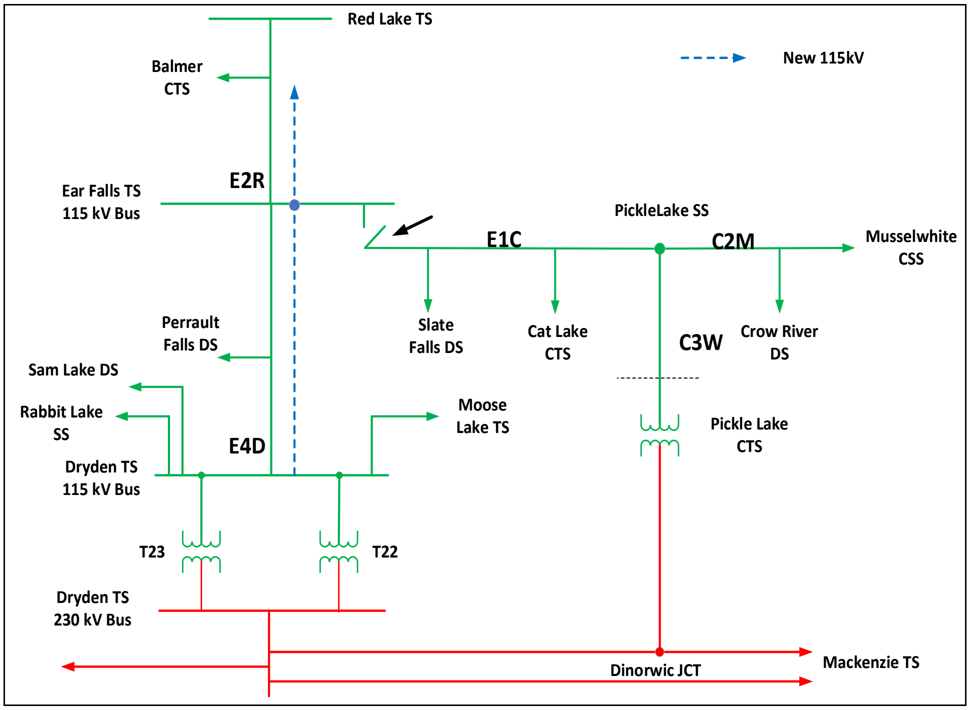

Figure 9: Alternative 2 Single Line Diagram – Building New 115kV Infrastructure

- Alternative 3 – Building a new 115kV Single Transmission Line from Ear Falls TS to Red Lake TS with E4D Upgrades:

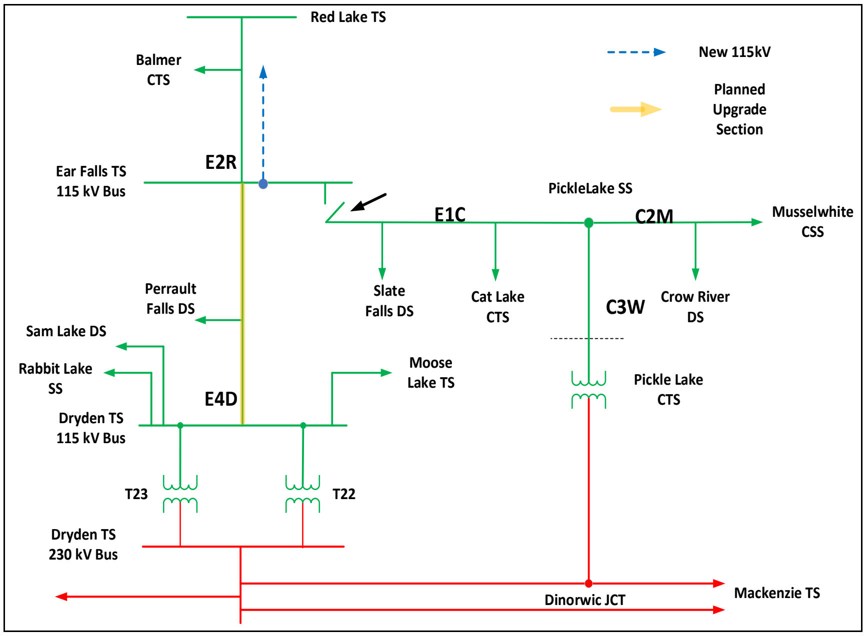

Figure 10: Alternative 3 Single Line Diagram - Building New 115kV Infrastructure and Upgrades on Existing Infrastructure

- Alternative 4 – Building a new 230kV Single Transmission Line from Dryden TS to Red Lake TS:

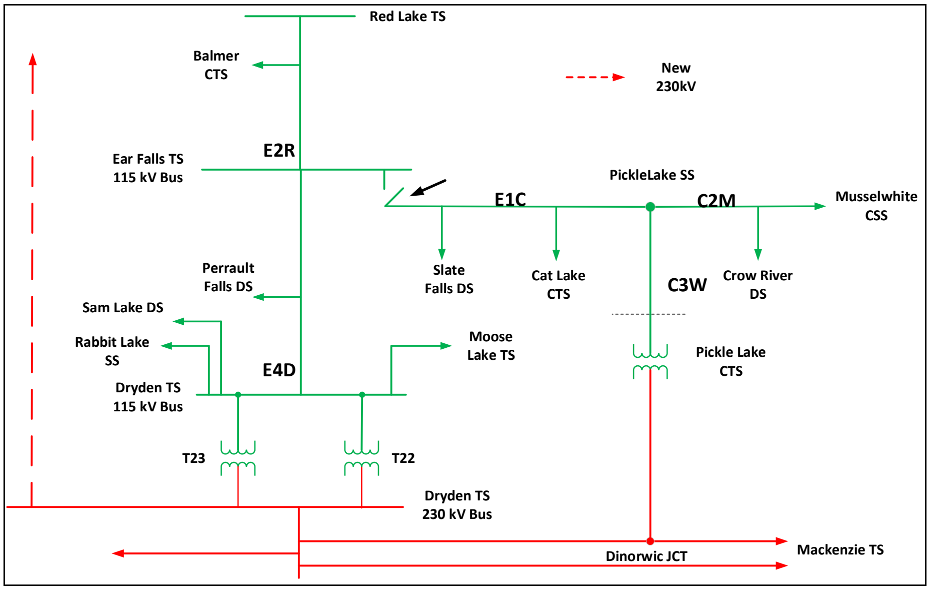

Figure 11: Alternative 4 Single Line Diagram - Building New 230kV Infrastructure

These options require the installation of appropriately sized voltage devices to mitigate pre-contingency voltage limitations. The planning allowance for these alternatives ranges from $125M to $375M, depending on the materialized load and the required infrastructure.

To determine the most cost-effective and beneficial solution to increase the area's load meeting capability, one of the project proponents has taken the lead in initiating a technical feasibility study with IESO and a physical feasibility study with Hydro One. These studies aim to thoroughly investigate the proposed alternatives and assess their economic viability and overall benefits. The goal is to identify the optimal solution that not only meets the area's increasing load demands but also ensures long-term reliability and system stability.

By conducting a detailed analysis and leveraging the expertise of Hydro One and IESO, it is expected to identify the most suitable course of action that maximizes cost-effectiveness and delivers significant value to all stakeholders in the area. The findings of this study will contribute to the decision-making process, enabling the selection of a preferred solution that aligns with the region's future growth plans.

8.3.2 M2W – 115kV – Capacity Needs under Mining Sector Development

The M2W circuit is a radial transmission line supplied from Marathon TS, consisting of two independent branches. One branch extends approximately 70 km in the north-east direction to Manitouwadge DS, while the other branch stretches eastward for about 100 km to White River DS.

There is a possible growing capacity need on the branch that leads towards Manitouwadge DS flagged by a customer connection application after the 2023 Northwest Ontario IRRP The section from Pic JCT to Manitouwadge JCT is the most constrained, with a continuous summer rating of 290 A, equivalent to approximately 57 MW. Recently, there has been significant interest from mining customers, with an anticipated growth of 30-80 MW by 2028. The 2022 summer peak demand on the M2W branch was 6.1 MW. Additionally, an industrial customer is planning a mining project of 50.9 MW by 2025-2026 on this branch. If the mining project proceeds as planned, the branch will start to experience capacity issues.

To address the potential need for additional capacity, the following alternatives are being considered:

- Alternative 1 - Upgrade the conductor and structures on the existing M2W circuit
- Alternative 2 - Building a new parallel 115kV circuit supplied from Marathon TS

Since the anticipated increase in mining sector load has not yet materialized, further assessment of the above alternatives for reinforcing the M2W circuit will be conducted to determine their cost and feasibility. These assessments will be undertaken in the event of a request from customers for additional load and upon reaching an agreement with them.

8.4 System Reliability, Operational and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2023-2033 to cater this need**.** Based on the results, the following system reliability and operation needs have been identified for this Region.

8.4.1 Fort Frances MTS Customer Reliability Need

Fort Frances MTS, a step-down transformer station that supplies LDC loads in Fort Frances, is supplied from the nearby Fort Frances TS via a single circuit 115kV line F1B. Line F1B extends approximately 20 km to the east of Fort Frances to also supply rural Hydro One LDC loads. The single circuit supply configuration results in Fort Frances MTS supply interruptions during certain transmission outages (planned and unplanned). Over the past 10 years, 90% of Fort Frances Power's customer interruptions is a due to transmission supply losses as reported by the Ontario Energy Board (OEB). Fort Frances LDC has indicated a reliability need due to the single circuit supply configuration as planned and unplanned outages causes community-wide power outages. Outage durations ranges from 4 to 8 hours with a total of 16MW load interrupted. Despite meeting the ORTAC criteria, the current supply configuration of the Fort Frances MTS remains highly disruptive for customers. However, considering the close proximity of Fort Frances MTS to Fort Frances TS, there is potential for cost-effective improvement solutions.

The two stations are located across the street from each other. Most of the Fort Frances MTS station equipment has exceeded their manufacture life span and will need to be replaced within the next 10-15 years. The current Fort Frances MTS station configuration also does not allow for any primary 115kV components to be isolated for maintenance purposes; therefore, the entire station must be de-energized to allow for primary components to be serviced or repaired. Considering all above, reconfiguration of the station will improve the supply interruptions for Fort Frances MTS.

The Fort Frances TS 115kV station layout and connection to Fort Frances MTS is shown in Figure 12. Fort Frances TS 115kV side is comprised of a six-breaker ring bus with connections to the station's two autotransformers and circuits K6F, F3M, F2B and F1B. Fort Frances MTS is currently connected to the F1B circuit which connects to L1 bus. Hydro One has proposed reconfiguration options with the goal of reducing Fort Frances MTS' exposure to transmission outages.

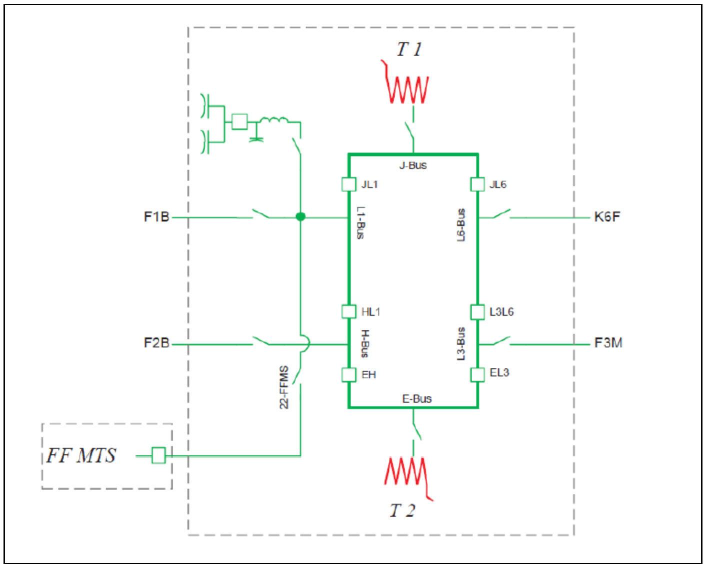

Figure 12: Fort France TS Single Line Diagram

Alternative 1:

Replace the existing 22-FFMS air-break switch with an interrupter switch (still connected to F1B) and install a second interrupter switch to connect Fort Frances MTS to F2B. One of the two switches would be operated normally open, but the switches would allow Fort Frances MTS to be transferred between F1B and F2B to avoid any supply interruptions during planned outages on either of the two circuits or buses.

Alternative 2:

Install a new 115kV breaker on the L1 bus and move the Fort Frances MTS termination between this new breaker and the HL1 breaker. This would form a 7-breaker ring bus and Fort Frances MTS would have its own position separate from any other circuit. This would still have the MTS on a single supply.

Alternative 3:

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

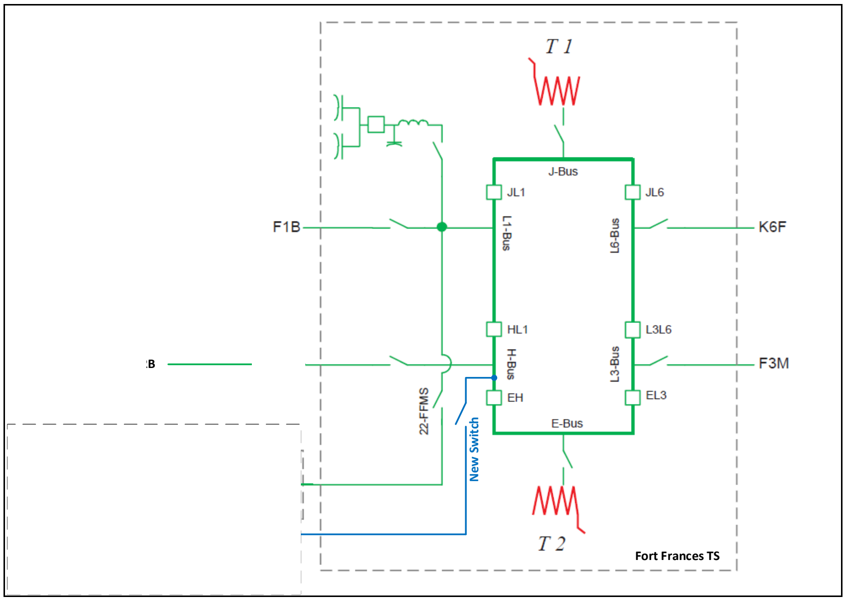

Figure 13: Fort Frances MTS Need Alternative 3

Alternative 4:
Install a second breaker and switch at Fort Frances MTS on the 115kV side, connecting it to 115kV circuit F2B via a drop feed. This creates a second supply for Fort Frances MTS, achieving full redundancy while tapping at a different location comparing to Alternative 3

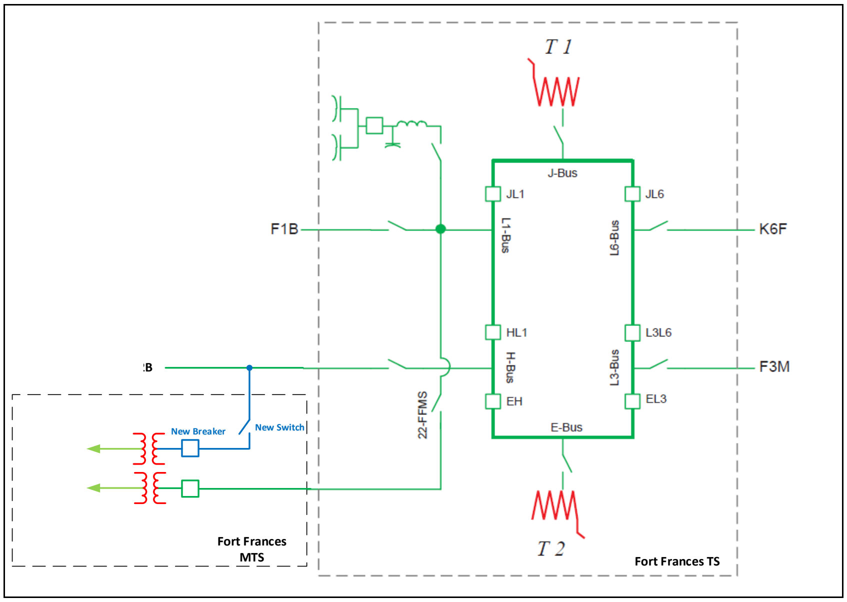

Figure 14: Fort Frances MTS Need Alternative 4

The LDC Fort Frances Power recommends alternative 4 as the optimal alternative for addressing the need. The interruptions caused by planned transmission supply outages can be effectively mitigated with the dual supply. This alternative also provides FFPC with the capability to isolate any primary station components for maintenance purposes without requiring a station-wide outage. Alternative 4 offers a robust station supply configuration that enhances reliability for current customers and accommodates potential significant load growth from industrial customers and electrification of the community. Fort Frances Power has started the preparation of the IESO SIA application package at the time of this RIP, and the project is planned for execution in the year 2026-2027. Additionally, the implementation of Alternative 4 will serve as a building block for the forthcoming Fort Frances MTS End-of-Life replacement project, contributing to its seamless execution.

8.4.2 E1C Operation and High Voltage Need

The Integrated Regional Resource Plan (IRRP), published in January 2023, identified operational challenges concerning the 115kV E1C transmission line. This line plays a critical role in the Pickle Lake area system, and its operational state significantly affects the system's overall performance. Two main challenges have been identified in the E1C operation. Limitations on supply capacity when E1C operates in a normally closed state and high voltage issues when it operates in a normally open state. A single line diagram of the area is presented in Figure 15.

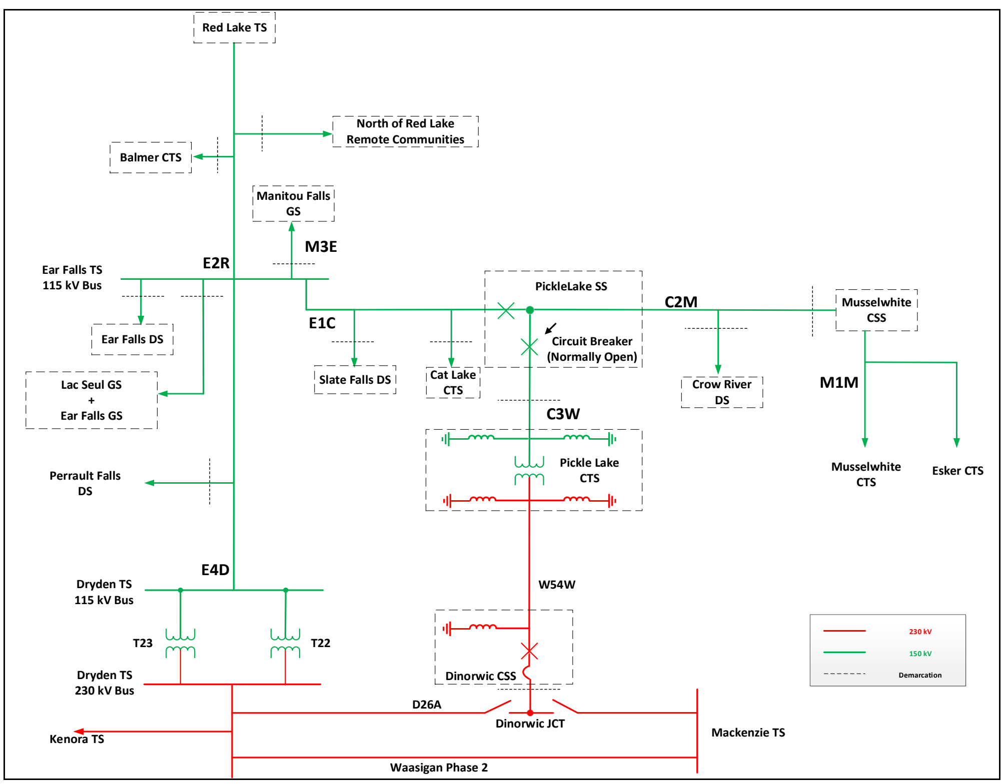

Figure 15: Dryden - Pickle Lake - Ear Falls - Red Lake Area Single Line Diagram

Operating the E1C in a closed state results in a loop configuration that restricts transfer capability through E4D and W54W, thereby limiting the area's overall potential for load increase. This limitation could potentially impact local business expansion. Moreover, if E4D were to fail, the local generations at Ear Falls TS would remain connected, potentially causing transient instability. To maintain system adequacy and meet forecast demand in the Ear Falls, Red Lake, and Pickle Lake areas, it is crucial to introduce a normally open point on the E1C line end. This change would offload E4D and shift the loading on the Pickle Lake area to the newly installed 230kV transmission line W54W. However, operating E1C in an open state would lead to high voltage issues under light load conditions, regardless of the E1C end that is opened. To resolve this problem, the following alternatives are being considered.

Alternative 1: Installation of a Remote-Controlled Switch at a Mid-Point of E1C and Operate E1C Normally Open at the New Switch Location

While opening E1C mid-point reduces most high-voltage issues and provides for more capacity on the E4D by shifting load supply to W54W, it would require an upgraded or newly installed isolation switch capable of being remotely operated from the control center. Closing the switch may be required at times under light load conditions and with unexpected events, involving failure of transmission equipment in the Pickle Lake or Ear Falls areas, could trigger the need to revert to the operating configuration in the Pickle Lake area as illustrated in Figure 15. This involves closing the switch and opening the circuit breaker at Pickle Lake SS. While using an existing switch (with no remote-control capability and no on-load switching capability) will be implemented as an interim solution; this alternative, as a permanent solution, is associated with a planning allowance of approx. $6M and the effectiveness and reliability of communications to this very remote site is low. In addition, sourcing independent and reliable AC and DC supplies for the switch will be challenging and expensive. Therefore, this alternative is considered and rejected as a permanent solution.

Alternative 2: Opening E1C on the Pickle Lake SS Line End with Reactor Installations at Cat Lake MTS or Ear Falls TS

This alternative was discussed with the TWG and was compared with alternative 3.

Opening E1C at the Pickle Lake SS end leads to a voltage as high as 132 kV on the E1C line end near Pickle Lake SS under a light load pre-contingency condition. It also results in multiple post-contingency violations. Consequently, a 10-15 Mvar shunt reactor would need to be installed near Cat Lake MTS or Ear Falls TS to implement this solution. The Ear Falls location would require site expansion. It is unknown at this time the physical feasibility of installing a high voltage shunt reactor at the MTS. As the short circuit level at the MTS is low, at least two reactor installations would be required to comply with the 4% voltage change criteria when switching a reactive device. Planning allowance is approximated to be $20M for an Ear Falls installation.

Alternative 3: Opening E1C on the Ear Falls TS Line End with Reactor Installations at Pickle Lake SS

This alternative mirrors alternative 2 but opens the other end of E1C. High voltage violations are less severe in this configuration, with pre-contingency voltages in the area staying within the ORTAC limit. The most critical contingency is the loss of one of the existing 20 Mvar reactors at Pickle Lake CTS. The TWG has confirmed that installing an additional 10 - 15 Mvar reactor at Pickle Lake SS would address the high voltage violation. Space is available at Pickle Lake SS for a reactor installation and the short circuit levels are sufficient at this station to require 1 reactive device in lieu of two smaller ones. Planning allowance is approximated to be $20M.

The TWG recommends Alternative 3 as the most effective solution. This approach only experiences high voltage violations under post-contingency scenarios, and the addition of a 10 -15 Mvar reactor can effectively mitigate these violations. Once this reactor is installed at Pickle Lake SS, the interim normally open point on E1C (mid-point) will be closed and the new normally open point made to be at Ear Falls TS; refer to Figure 16 for the recommended solution. Once the project is initiated, the TWG will investigate and refine the automatic reactor switching scheme recommended in IRRP.

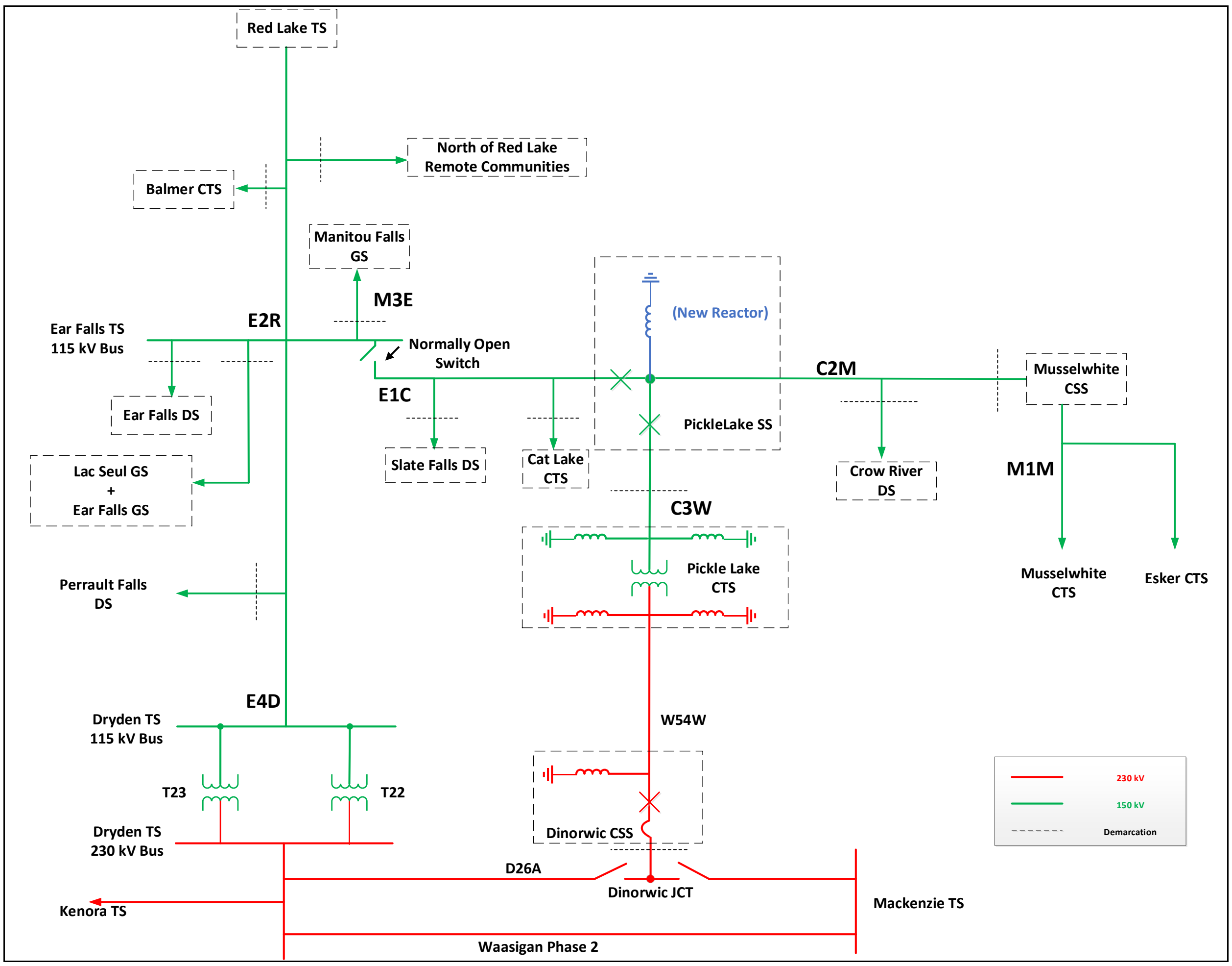

Figure 16: E1C Operation Recommended Solution

8.5 Other Planning Considerations

8.5.1 Fort William TS Shunt Capacitor Banks Replacement

Fort William TS, a step-down station in southeastern Thunder Bay, is supplied by 115kV transmission circuits B5 and B15, providing power to the suburban area. The station comprises of two 115/25 kV transformers with capacities of 50/66.6/83.3 MVA each. Additionally, Fort William TS relies on temporary capacitors on trailers, namely SC1 and SC2, which have been in service for a considerable period. SC1 and SC2 are rated at 14.88 Mvar and 15.77 Mvar respectively, operating at 25 kV. However, both capacitor banks have been assessed in poor conditions and as obsolete.

Presently, SC1 is scheduled for maintenance ensuring that SC1 remains available for service when needed. SC2 is in a significantly deteriorated condition, requiring extensive repairs both in terms of time and costs. It is crucial to address the concerns for supporting local loads and satisfying IESO's contingency planning criteria for both capacitor banks. Therefore, the following alternatives have been considered in this RIP:

Alternative 1: Maintain Status Quo

This alternative was considered and rejected as it does not address the deteriorated condition and the reliance on temporary mobile units, which could reduce supply reliability for customers.

Alternative 2: Refurbish the Existing Units

This alternative was considered and rejected due to the asset condition. SC2 has suffered damage with parts stolen and missing, making refurbishment a significant and non-economic investment with higher future maintenance requirements.

Alternative 3: Replacement for Both Units.

This alternative will provide new permanent shunt capacitors which are appropriately configured to ensure reliable supply to customers and fulfill system contingency planning criteria.

The TWG recommends alternative 3 as the preferred and cost-effective solution. Given the asset condition, refurbishing SC2 is not deemed worthwhile compared to the effort required for replacement. Recognizing the criticality of these units for local system reliability, Hydro One is initiating a project, with a planning allowance of $6M, to replace both units with similar equipment. Simultaneously, SC1 is scheduled for maintenance to ensure its functional operation until replacement.

By implementing alternative 3, Fort William TS will address the significant deteriorated assets issue, meet contingency planning criteria, and maintain a reliable power supply to customers.

8.5.2 Greenstone - Marathon Area System Needs

In Northwest Ontario, there continues to be interest in additional loads and generation connections in the Greenstone-Marathon sub-region. Alternatives presented in the past IRRPs, and RIPs remain valid. Further assessment of those alternatives for reinforcing the area will be conducted to determine their cost and feasibility. These assessments will be undertaken in the event of a request from customers for additional load and upon reaching an agreement with them.

8.5.3 Supply to the Ring of Fire

The Ring of Fire is a remote area approximately 500 km north of Thunder Bay rich in critical minerals but without grid power supply. As per the 2023 Northwest Ontario IRRP, there are a few options to energize the Ring of Fire area. With renewed interest in developing the Ring of Fire from both government and mining companies, the IESO is updating its Supply to the Ring of Fire study to help inform government policy and potential customers seeking connection. Preliminary findings were included in the 2023 Northwest IRRP. The scope and timing of the IESO's ongoing study will evolve with government policy direction.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure Plan report for Northwest Ontario region. The Major infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2023-2033 are provided in Table 16 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 16: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Rabbit Lake SS	Replacement 115kV switchyard and associated equipment	Hydro One Transmission	2024-2027	$35.2M
Whitedog Falls SS	Replacement three 115kV breakers, DC station services and associated equipment	Hydro One Transmission	2025-2028	$8.5M
Mackenzie TS	Replacement of one 230/115kV autotransformer, five 230kV breakers, four switches, AC station services and associated equipment	Hydro One Transmission	2025-2028	$54.6M
Wawa TS	Replacement of one 230/115kV autotransformer, associated breakers and equipment and station services	Hydro One Transmission	2026-2029	$43.8M
Marathon TS	Replacement of 230kV and 115kV breakers and associated equipment	Hydro One Transmission	2026-2029	$14.6M
Lakehead TS	Replacement of 230kV and 115kV breakers, station services and associated equipment	Hydro One Transmission	2028-2031	$41.5M
Lakehead TS Condenser C8 Replacement	Replace Condenser C8 with a +60/-40 Mvar STATCOM	Hydro One Transmission	2027	$40.6M
Fort Frances TS	Replacement of 230kV breakers, associated equipment, and station services	Hydro One Transmission	2029-2032	$20.3M
Kenora TS	Replacement of 230kV breakers, associated equipment, and station services	Hydro One Transmission	2030-2033	$17M

Station Capacity Needs				
Margach DS	Monitor and implement investment plan in 2025	Hydro One Distribution	2025	$1M
Crilly DS	Further assess the Alternative 1 and Alternative 2 from this RIP	Hydro One Distribution	NA	NA
White Dog DS	Monitor and review in next planning cycle	Hydro One Distribution	NA	NA
White River DS	Monitor and review in next planning cycle	Hydro One Distribution	NA	NA
Kenora MTS	Further assess the alternatives from this RIP; monitor and review in next planning cycle	Synergy North	NA	NA
Sam Lake DS	Install fan monitoring – Refer to Local Planning for more detail	Hydro One Distribution and Sioux Lookout Hydro	2023	$1.5M
Transmission Line Capacity Needs				
E2R and E4D	Further evaluation on the four alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	$125M-375M
M2W	Further evaluation on the 2 alternatives based on mining customers' requests	Hydro One Transmission and Proponent	TBD	TBD
System Reliability, Operation and Load restoration Needs				
Fort Frances MTS	Install a second breaker and switch in Fort Frances MTS to create a second supply to the MTS	Fort Frances Power	2026-2027	$0.85M
E1C Operation	Open E1C end at Ear Falls TS and install a 10 – 15 MVAR shunt reactor at Pickle Lake SS	Hydro One Transmission	2026-2027	$20M
Other Planning Considerations				
Fort Williams TS Shunt Capacitor	Temporary capacitors to be replaced with permanent units	Hydro One Transmission	2026-2027	$6M

Banks Replacement				
Greenstone-Marathon Area System Needs	Further evaluation of the alternatives presented in the past IRRPs and RIP upon customers' requests	Hydro One Transmission and Proponent	TBD	TBD
Supply to the Ring of Fire	IESO to update Supply to the Ring of Fire study	IESO	TBD	TBD

Note:

a) The planned in-service dates are tentative and subject to change
b) Costs are based on budgetary planning estimates/allowance and excludes the cost for distribution infrastructure (if required)

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Winter Weather Adjusted Net Load Forecast

Table A.1: Northwest Ontario Region – Winter Non-Coincident- Net Load Forecast

Transformer Station Name	DESN ID	LTR (MVA)	LV Cap	LTR (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Agimak DS	T1/T2	12.0	N	10.80	5.14	5.15	5.18	5.24	5.30	5.36	5.43	5.49	5.57	5.64	5.72	5.90	5.95	6.01	6.06	6.12	6.17	6.23	6.32	6.39	6.46
Barwick DS	T1/T2	65.4	Y	62.13	27.61	27.58	27.69	27.86	28.02	28.19	28.35	28.51	28.71	28.79	29.00	23.68	23.88	24.07	24.26	24.45	24.64	24.84	24.12	23.85	23.58
Beardmore DS # 2	T2	12.0	N	10.80	1.67	1.62	1.62	1.64	1.65	1.66	1.75	1.75	1.71	1.72	1.74	1.69	1.70	1.72	1.73	1.74	1.75	1.77	1.77	1.78	1.78
Birch TS	T2/T3/T4	111.6	Y	106.02	74.30	74.25	73.91	73.83	74.12	74.63	74.71	74.79	75.26	75.77	76.10	78.77	79.05	79.46	79.82	80.23	80.68	81.03	81.24	81.72	82.20
Burleigh DS	31T1	11.6	N	10.44	4.70	5.12	5.12	5.13	5.15	5.17	5.18	5.19	5.21	5.22	5.24	5.65	5.68	5.71	5.73	5.76	5.79	5.82	5.91	5.96	6.02
Cat Lake MTS	T1	3.0	N	2.70	1.05	1.05	1.06	1.07	1.09	1.10	1.12	1.13	1.15	1.17	1.18	1.18	1.19	1.21	1.22	1.23	1.25	1.26	1.27	1.29	1.30
Clearwater Bay DS	40T1	10.4	N	9.36	6.37	6.36	6.36	6.37	6.39	6.41	6.41	6.41	6.42	6.43	6.44	7.17	7.21	7.24	7.27	7.30	7.33	7.36	7.43	7.50	7.57
Crilly DS (Sturgeon Falls CGS)	23T1	2.4	N	2.16	2.14	2.14	2.15	2.16	2.18	2.19	2.20	2.21	2.23	2.24	2.25	2.49	2.51	2.53	2.54	2.56	2.58	2.60	2.63	2.66	2.69
Crow River DS	21T1/21T2	11.6	N	10.44	3.32	3.32	3.33	3.35	3.37	3.39	3.42	3.44	3.46	3.49	3.52	3.62	3.64	3.66	3.68	3.71	3.73	3.75	3.78	3.81	3.84
Dryden TS	T4/T5	63.3	N	56.97	20.74	20.82	20.99	21.20	21.47	21.71	21.95	22.17	22.42	22.71	22.81	22.42	22.70	22.97	23.25	23.52	23.80	24.08	24.10	24.29	24.48
Ear Falls DS	T5	11.6	N	10.44	6.01	6.00	6.01	6.05	6.10	6.15	6.22	6.27	6.35	6.41	6.48	6.38	6.41	6.45	6.49	6.52	6.56	6.60	6.66	6.70	6.73
Eton DS	T1	12.0	N	10.80	4.13	4.14	4.15	4.16	4.18	4.20	4.21	4.21	4.22	4.23	4.25	4.72	4.75	4.79	4.82	4.85	4.88	4.91	4.95	5.01	5.06
Fort Frances MTS	T2/T3	26.6	N	23.94	16.23	16.20	16.21	16.27	16.33	16.39	16.46	16.53	16.63	16.72	16.83	17.79	17.88	17.97	18.06	18.15	18.24	18.33	18.48	18.62	18.77
Fort William TS	T5/T6	109.4	N	103.93	79.15	79.30	79.25	79.10	79.50	80.12	80.28	80.44	85.03	85.62	86.11	89.88	90.42	91.04	91.68	92.34	93.00	93.65	95.15	96.19	97.22
Jellico DS # 3	T1	2.4	N	2.16	0.71	0.71	0.71	0.71	0.71	0.72	0.72	0.73	0.73	0.74	0.75	0.75	0.75	0.75	0.76	0.76	0.76	0.77	0.77	0.78	0.78
Keewatin DS	T1	11.6	N	10.44	5.42	5.42	5.43	5.45	5.47	5.50	5.50	5.51	5.52	5.53	5.54	6.21	6.24	6.28	6.32	6.36	6.40	6.43	6.49	6.56	6.63
Kenora DS	T1	12.0	N	10.80	6.79	6.81	6.84	6.88	6.92	6.98	7.01	7.04	7.08	7.11	7.16	7.75	7.81	7.88	7.94	8.00	8.07	8.13	8.20	8.29	8.38
Kenora MTS	-	26.0	N	23.40	21.49	21.76	21.95	22.15	22.52	22.95	23.25	23.56	23.86	24.17	24.45	25.88	26.12	26.53	26.79	27.14	27.55	27.81	28.24	28.64	29.04
Longlac TS	T2	47.6	Y	45.22	21.45	21.39	15.80	15.97	16.15	16.33	16.58	16.80	17.08	17.33	17.59	17.38	17.52	17.67	17.81	17.95	18.09	18.24	17.35	17.32	17.29
Manitouwadge DS	19T1	9.6	N	8.64	1.40	1.39	1.40	1.40	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.60	1.60	1.61	1.62	1.63	1.64	1.64	1.66	1.68	1.69
Manitouwadge TS	T1	41.7	N	37.53	10.34	18.84	18.92	19.11	19.32	19.54	19.82	20.09	20.41	20.69	21.00	19.94	20.09	20.25	20.41	20.56	20.72	20.88	22.04	22.30	22.57
Marathon DS	2375T1	11.6	N	10.44	8.11	8.15	8.19	8.26	8.34	8.41	8.48	8.54	8.61	8.68	8.76	10.49	10.59	10.69	10.80	10.90	11.00	11.10	11.34	11.55	11.76
Margach DS	T2	11.6	N	10.44	10.50	10.48	10.47	10.48	10.51	10.53	10.53	10.53	10.55	10.55	10.61	15.33	15.39	15.45	15.51	15.57	15.63	15.68	16.28	16.68	17.08
Minaki DS	T1	12.0	N	10.80	0.87	1.70	1.69	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.82	1.83	1.83	1.84	1.84	1.85	1.85	1.95	1.98	2.00
Moose Lake TS	T2/T3	12.2	N	10.98	7.78	7.73	7.78	7.77	7.76	7.76	7.76	7.75	7.76	7.77	7.78	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.72	7.71	7.71
Murillo DS*	T1/T2	13.0	N	11.70	19.55	19.56	19.58	19.63	19.69	19.76	19.76	19.76	19.77	19.78	19.80	21.27	21.34	21.40	21.45	21.50	21.55	21.59	21.78	21.93	22.08
Nestor Falls DS	T1	11.6	N	10.44	3.75	3.75	3.75	3.76	3.77	3.78	3.79	3.79	3.80	3.81	3.83	4.21	4.22	4.24	4.26	4.28	4.30	4.32	4.36	4.40	4.44
Nipigon DS	24T1	11.6	N	10.44	4.07	4.09	4.11	4.14	4.18	4.22	4.26	4.30	4.34	4.38	4.43	4.57	4.61	4.65	4.69	4.73	4.77	4.81	4.86	4.90	4.95
Perrault Falls	36T1	11.6	N	10.44	0.52	0.52	0.53	0.53	0.53	0.54	0.54	0.55	0.55	0.56	0.56	0.59	0.59	0.60	0.60	0.61	0.61	0.62	0.62	0.63	0.64
Pic DS	1504T2	12.0	N	10.80	8.07	13.27	13.28	13.31	13.34	9.13	9.15	9.17	9.20	9.23	9.26	6.80	6.84	6.89	6.93	6.97	7.02	7.06	5.74	5.38	5.02
Port Arthur TS	T1/T2	61.4	N	55.26	36.98	37.10	37.02	37.39	37.73	38.17	38.37	38.61	38.58	39.00	38.91	41.45	41.39	41.86	41.83	42.06	42.55	42.52	43.12	43.50	43.88
Red Lake TS	T3/T4	61.5	Y	58.43	31.04	33.98	34.32	34.69	35.09	35.47	30.75	31.23	31.77	32.23	32.67	31.73	32.14	32.54	32.95	33.36	33.78	34.19	32.82	32.81	32.79
Redrock DS	33TT1	9.6	N	8.64	4.51	4.49	4.49	4.50	4.51	4.53	4.53	4.54	4.55	4.56	4.58	4.12	4.14	4.15	4.16	4.18	4.19	4.21	4.14	4.11	4.08
Sam Lake DS	2501T1/2501T2	24.0	N	21.60	28.22	28.47	28.67	28.70	28.72	28.74	28.74	28.74	28.78	28.81	28.87	30.53	30.64	30.74	30.86	30.97	31.08	31.19	31.33	31.52	31.71
Sapawe DS	11T1/11T2	4.8	N	4.32	4.50	4.51	4.52	4.54	4.57	4.60	4.62	4.64	4.66	4.68	4.71	4.90	4.93	4.97	5.00	5.04	5.07	5.11	5.13	5.17	5.20
Schreiber Winnipeg DS	34T1	9.6	N	8.64	5.80	5.81	5.83	5.87	5.91	5.95	5.98	6.01	6.04	6.08	6.12	6.83	6.88	6.93	6.98	7.03	7.08	7.14	7.23	7.32	7.41
Shabaqua DS	32T1	9.6	N	8.64	3.32	3.32	3.32	3.33	3.35	3.36	3.37	3.39	3.40	3.42	3.44	3.69	3.71	3.73	3.75	3.77	3.78	3.80	3.84	3.87	3.91
Sioux Narrow DS	27T1	12.0	N	10.80	5.01	5.01	5.01	5.03	5.05	5.07	5.08	5.09	5.11	5.12	5.14	5.66	5.69	5.72	5.75	5.78	5.80	5.83	5.89	5.95	6.01
Slate Falls DS	T1	4.7	N	4.23	0.77	0.77	0.77	0.77	0.78	0.78	0.79	0.79	0.80	0.80	0.81	0.84	0.85	0.85	0.86	0.86	0.87	0.88	0.88	0.89	0.90
Valora DS	30T1	4.8	N	4.32	0.96	0.96	0.97	0.99	1.00	1.01	1.03	1.04	1.05	1.07	1.08	1.16	1.17	1.19	1.20	1.22	1.23	1.25	1.26	1.28	1.30
Vermillion Bay DS	31T1	9.6	N	8.64	2.65	2.66	2.68	2.70	2.73	2.75	2.78	2.80	2.83	2.85	2.88	2.85	2.87	2.90	2.93	2.96	2.99	3.01	3.02	3.04	3.06
White Dog DS	-	3.2	N	2.88	2.80	2.82	2.85	2.87	2.92	2.95	2.99	3.01	3.05	3.07	3.11	3.08	3.12	3.16	3.20	3.24	3.28	3.32	3.33	3.36	3.39
Whiteriver DS	36T1	15.6	N	14.04	13.42	13.51	13.69	13.80	13.91	14.00	14.09	14.18	14.27	14.35	14.44	12.15	12.23	12.31	12.39	12.47	12.54	12.62	12.42	12.32	12.22
Pickle Lake Cluster	-	-	-	-	9.57	9.85	10.14	10.43	10.74	11.06	11.39	11.73	12.08	12.44	12.81	13.19	13.59	14.13	14.70	15.29	15.90	16.53	17.20	17.88	18.60
Red Lake Cluster	-	-	-	-	9.93	10.24	10.57	10.90	11.24	11.60	11.97	12.35	12.74	13.15	13.57	14.01	14.46	15.04	15.64	16.26	16.91	17.59	18.29	19.02	19.79

Appendix B: Lists of Step-Down Transformer Stations

Sr.NO	Transformer Station	Voltage (kV)	Supply Circuit
1	EAR FALLS TS	115/44	M3E, E4D, E1C, E2R
2	RED LAKE TS	115/44	E2R
3	CAT LAKE MTS	115/25	E1C
4	CROW RIVER DS	115/25	C2M
5	PERRAULT FALLS DS	115/12.5	E4D
6	SLATE FALLS DS	115/24.9	E1C
7	LONGLAC TS	115/44	A4L
8	MANITOUWADGE TS	115/44	M2W
9	MARATHON TS	230/115	T1M, W21M, M23L, M2W, M24L, W22M
10	BEARDMORE DS #2	115/25	A4L
11	JELLICOE DS #3	115/12.5	A4L
12	MANITOUWADGE DS #1	115/12.5	M2W
13	MARATHON DS	115/25	T1M
14	PIC DS	115/25	M2W
15	SCHREIBER WINNIPEG DS	115/12.5	A5A
16	WHITE RIVER DS	115/25	M2W
17	BARWICK TS	115/44	K6F
18	DRYDEN TS	230/115	K3D, D26A, E4D, D5D, K23D, M2D
19	FORT FRANCES TS	232/115	K24F, F25A, K6F, F1B, F2B, F3M
20	KENORA TS	230/115	K24F, K7K, K21W, K23D, K22W
21	MACKENZIE TS	230/115	D26A, A22L, A3M, F25A, A21L, N93A
22	MOOSE LAKE TS	115/44	A3M, M1S, M2D, B6M
23	FORT FRANCES MTS	115/12.47	F1B
24	KENORA MTS	115/12.5	15M1
25	AGIMAK DS	115/25	29M1
26	BURLEIGH DS	115/12.5	F1B
27	CLEARWATER BAY DS	115/25	SK1
28	ETON DS	115/12.48	K3D

29	KEEWATIN DS	115/12.5	SK1
30	MARGACH DS	115/25	K6F
31	MINAKI DS	115/25	K4W
32	NESTOR FALLS DS	115/12.5	K6F
33	SAM LAKE DS	115/25	K3D
34	SAPAWE DS	115/12.5	B6M
35	SHABAQUA DS	115/12.5	B6M
36	SIOUX NARROWS DS	115/12.5	K6F
37	VALORA DS	115/25	29M1
38	VERMILION BAY DS	115/12.5	K3D
39	BIRCH TS	115/28.4	B9, P7B, B14, B5, R2LB, P3B, B15, R1LB, B6M
40	FORT WILLIAM TS	115/25	B5, B15
41	LAKEHEAD TS	230/115	A22L, M23L, A21L, R2LB, L4P, M24L, A7L, R1LB, A8L, L3P
42	PORT ARTHUR TS #1	115/25	P7B, P1T, A6P, L4P, P3B, P5M, L3P
43	MURILLO DS	115/25	B6M
44	NIPIGON DS	115/12.5	57M1
45	RED ROCK DS	115/12.5	56M1
46	Pickle Lake CTS	230/115	W54W
47	NORTH CARIBOU LAKE TS (D)	115/25	WCD
48	MUSKRAT DAM TS (E)	115/25	WDE
49	BEARSKIN LAKE TS (F)	115/25	WEF
50	SACHIGO LAKE TS (G)	115/25	WEG
51	KINGFISHER LAKE TS (J)	115/44/25	WCJ
52	WUNNUMIN LAKE TS (I)	44/25	WJI
53	WAWAKAPEWIN TS (K)	115/44/25	WJK
54	KASABONIKA LAKE TS (L)	44/25	WKL
55	KI-WAPEKEKA TS (M)	115/25	WKM
56	PIKANGIKUM TS (Q)	115/25	WPQ

57	POPLAR HILL TS (S)	115/25	WRS
58	DEER LAKE TS (U)	115/25	WTU
59	SANDY LAKE TS (W)	115/25	WZW
60	NORTH SPIRIT LAKE TS (V)	115/44/25	WZV
61	KEEWAYWIN TS (Y)	115/25	WVY

Appendix C: Lists of Transmission Circuits

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Mackenzie x Dryden	D26A	230
2	Mackenzie x Fort Frances	F25A	230
3	Dryden x TCPL Vermill Bay x Kenora	K23D	230
4	Fort Frances x Kenora	K24F	230
5	Mackenzie x Marmion Lake x Atikokan	N93A	230
6	Kenora x Whiteshell (Manitoba Hydro)	K21W	230
7	Kenora x Whiteshell (Manitoba Hydro)	K22W	230
8	Mackenzie x Lakehead	A21L	230
9	Mackenzie x Lakehead	A22L	230
10	Marathon x Lakehead	M23L	230
11	Marathon x Lakehead	M24L	230
12	Marathon x Lakehead	M37L	230
13	Marathon x Lakehead	M38L	230
14	Wawa x Marathon	W21M	230
15	Wawa x Marathon	W22M	230
16	Wawa x Marathon	W35M	230
17	Wawa x Marathon	W36M	230
18	Dinorwic Jct x Pickle Lake	W54W	230
19	Kenora x Rabbit Lake	15M1	115
20	Ignace x Camp Lake x Valora x Mattabi	29M1	115
21	Mackenzie x Moose Lake	A3M	115
22	Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	B6M	115
23	Dryden x Domtar Dryden	D5D	115
24	Fort Frances x Burleigh	F1B	115

25	Fort Frances x Internat Fls (Minnesota Power)	F3M	115
26	Kenora x Norman	K2M	115
27	Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	K3D	115
28	White Dog x Minaki x Rabbit Lake	K4W	115
29	Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	K6F	115
30	Kenora x Weyerhaeuser Ken x Rabbit Lake	K7K	115
31	Moose Lake x Valerie Falls x Mill Creek	M1S	115
32	Moose Lake x Ignace x Dryden	M2D	115
33	Rabbit Lake x Keewatin x Forgie	SK1	115
34	White Dog x Caribou Falls	W3C	115
35	Nipignon x Red Rock	56M1	115
36	Reserve x Nipignon	57M1	115
37	Alexander x Port Arthur	A6P	115
38	Lakehead x Port Arthur	L3P	115
39	Lakehead x Port Arthur	L4P	115
40	Port Arthur x Birch	P3B	115
41	Port Arthur x Birch	P7B	115
42	Port Arthur x Conmee	P5M	115
43	Thunder Bay x Birch	B9	115
44	Thunder Bay x Birch	B14	115
45	Thunder Bay x Birch	B5	115
46	Thunder Bay x Birch	B15	115
47	Lakehead x Pine Portage x Birch	R1LB	115
48	Lakehead x Pine Portage x Birch	R2LB	115
49	Silver Falls x Lac Des Iles x Conmee	S1C	115
50	Aguasabon x Terrace Bay	A1B	115

51	Alexander x Nipignon x Beardmore x Jellicoe x Roxmark x Longlac	A4L	115
52	Alexander x Minnova x Schreiber x Aguasabon	A5A	115
53	Alexander x Cameron Falls	C1A	115
54	Alexander x Cameron Falls	C2A	115
55	Alexander x Cameron Falls	C3A	115
56	Upper White River x Lower White River	GA1	115
57	Marathon x Black River x Umbata Falls x Hemlo Mine x White River	M2W	115
58	Alexander x Pine Portage	R9A	115
59	Ear Falls x Selco x Slate Falls x Cat Lake x Pickle Lake	E1C	115
60	Pickle Lake x Crow River x Musselwhite	C2M	115
61	Pickle Lake x Wataynikaneyap	C3W	115
62	Ear Falls x Balmer x Red Lake	E2R	115
63	Ear Falls x Scout Lake x Dryden	E4D	115
64	Manitou Falls x Ear Falls	M3E	115
65	Terrace Bay x Marathon	T1M	115
66	Pickle Lake x Ebane/Pipestone	WBC	115
67	Ebane/Pipestone x North Caribou Lake	WCD	115
68	North Caribou Lake x Muskrat Dam	WDE	115
69	Muskrat Dam x Bearskin Lake	WEF	115
70	Muskrat Dam x Sachigo Lake	WEG	115
71	Ebane/Pipestone x Kingfisher Lake	WCJ	115
72	Kingfisher Lake x Wunnumin	WJI	44
73	Kingfisher Lake x Wawakapewin	WJK	115
74	Wawakapewin x Kasabonika Lake	WKL	44
75	Wawakapewin x KI-Wapekeka	WKM	115
76	Red Lake x Pikangikum	WPQ	115

77	Pikangikum x Poplar Hill SS / TS	WQR / WRS	115
78	Poplar Hill SS x Deer Lake SS / TS	WRT / WTU	115
79	Deer Lake SS x Sandy Lake SS	WTZ	115
80	Sandy Lake SS x Sandy Lake TS	WZW	115
81	Sandy Lake SS x North Spirit Lake	WZV	115
82	North Spirit Lake x Keewaywin	WVY	115

Appendix D: List of LDC's

Sr. no.	Name of LDC
1	Atikokan Hydro Inc.
2	Fort Frances Power Corporation
3	Hydro One Networks Inc. (Distribution)
4	Sioux Lookout Hydro Inc.
5	Synergy North

Appendix E: List of Districts[5] in the region

Sr. no.	Name of District
1	Kenora
2	Rainy River
3	Thunder Bay

[5] In Northern Ontario, Districts are in place of Municipalities.

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor

PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station