Bulk System Reactive Requirements in Northern Ontario

IESO Technical Report

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List of Abbreviations

APO	Annual Planning Outlook
EWTE	East West Tie East
EWTW	East West Tie West
FN	Flow North
FS	Flow South
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LTE	Long-Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MISSE	Mississagi East
MISSW	Mississagi West
MW	Megawatt
Mvar	Megavar
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NE	Northeast
NW	Northwest
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
RSVC	Reactive Support and Voltage Control
SC	Synchronous Condenser
SIA	System Impact Assessment
SS	Switching Station
SSM	Sault Ste. Marie
STE	Short-Term Emergency
STATCOM	STATic synchronous COMpensator
SVC	Static VAR Compensator
TS	Transformer Station

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Executive Summary

This report documents the findings and recommendations from a voltage study undertaken to identify reactive requirements across northern Ontario. The objective of this study was to confirm and address the following needs in a coordinated fashion given that a large number of changes are expected across northern Ontario in the coming decade:

- Address operational challenges in managing high voltages that exist today;
- Identify reactive requirements to support the integration of several planned new transmission lines, acknowledging that they will provide additional capacitive injection to the bulk transmission system when they are lightly loaded; and
- Confirm the capacitive requirements to support the Northeast Bulk Plan[1], which identified a need for dynamic reactive support but did not make a recommendation.

The following needs were identified through this study:

- High voltage issues in the Northwest and Northeast systems today under outage conditions;
- High voltage issues under light load/low transfer conditions following the incorporation of new transmission lines through the Waasigan project and the Northeast Bulk plan recommendations.
- Low voltage and voltage drop in the Northeast system following the loss of the new transmission line from Sudbury to Mississagi with forecast demand growth.

To address these needs, this study explored options including static and dynamic reactive devices and assessed various locations for these devices based on cost and effectiveness in addressing the needs.

The needs, recommendations and associated cost estimates are summarized in Table 1. The total estimated capital cost[2] of the proposed reactive devices is approximately $190 million. The implementation of this plan will be staged, with the recommended devices coming in service between 2025 and 2029.

Table 1 | Summary of Needs and Recommendations

Need	Need Timing	Recommendation	Location	Estimated Cost (M$)
To control high voltages under outage conditions	Today*	Two new reactors (-60 Mvar each)	Porcupine TS T7 and T8 tertiary windings	20

[1] The published plan can be found at https://www.ieso.ca/en/Get-Involved/Regional-Planning/Northeast-Ontario/bulk-planning

[2] This is based on planning level estimates with expected variance of +100% / –50%.

To control high voltages under outage conditions	Today*	One new reactor (-40 Mvar each)	Lakehead TS 230 kV	10
To improve operational flexibility	Today*	Two new reactors to replace the R1 (-40 Mvar each)	Lakehead TS 230 kV	20
Support Waasigan project	2025	Two new reactors (-40 Mvar each)	Mackenzie TS 230 kV	20
Support NE Bulk Plan	2029	One New line reactor (-120 Mvar)	Mississagi TS end of new 500 kV circuit	20
		One New STATCOM (±100 Mvar)	Mississagi TS 230 kV	50
		One New STATCOM (±100 Mvar)	Algoma TS 230 kV	50

* While the need exists today, it is understood that the recommended solutions will take time to implement. Targeted in-service dates for all recommendations will be documented in a letter from the IESO to the transmitter.

The transmitter will confirm the detailed specification and connection configuration of the proposed new devices. As part of the implementation of these recommendations, the IESO recommends that all new shunt devices be incorporated into local reactor or capacitor switching schemes[3]. Additionally, in order to address local voltage performance issues in Northwest, this study recommends that the switching schemes for all existing shunt capacitors and reactors in Northwest system be reviewed as per previous studies[4]. This includes the following considerations:

- Review the implementation of voltage based switching schemes for the reactors at Marathon TS and Wawa TS;
- Review reactor switching voltage settings at Mackenzie TS, Fort Frances TS and Kenora TS;
- Include the existing Watay system reactors at Dinorwic Junction and Pickle Lake SS in local voltage-based switching schemes.

The IESO will continue working with Transmitters throughout the implementation of this plan.

[3] Where the schemes already exist, these schemes should be reviewed to ensure proper coordination of device switching.

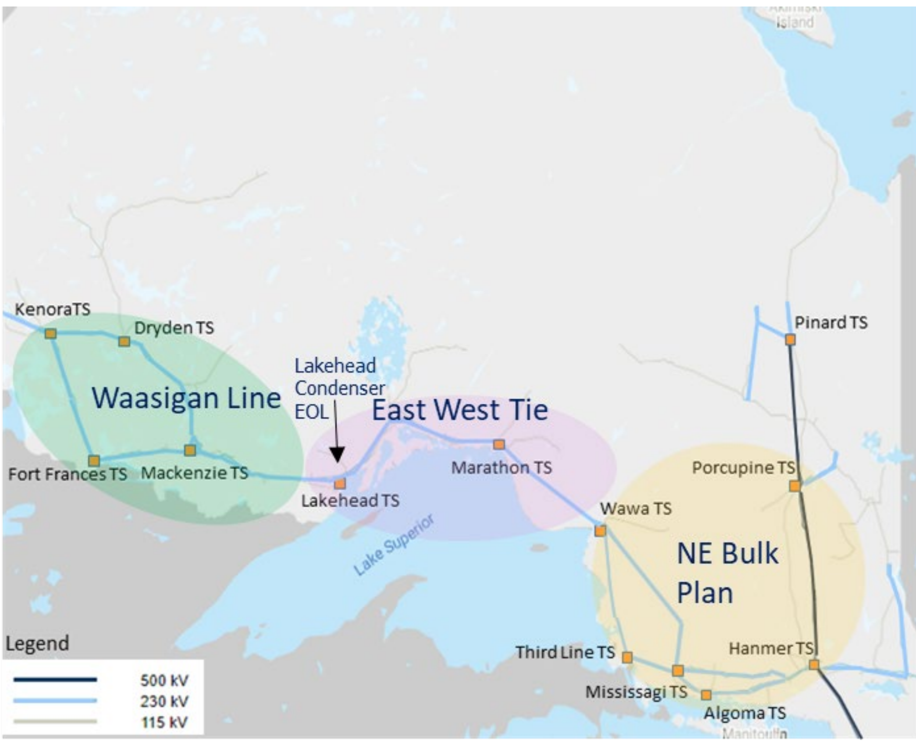
[4] IESO_REP_0822 Northwest Reactive Study.

1. Background and Scope

1.1 Background

This study examines reactive requirements across northern Ontario and makes recommendations for investments in new reactive devices to meet identified needs. It was initiated to provide a comprehensive and co-ordinated approach to assess the reactive requirements of the northern Ontario bulk power system in light of existing operational challenges, as well as several transmission reinforcement projects that are planned or underway as shown in Figure 1.

Figure 1 | Location of Northern Ontario Bulk Transmission System Reinforcements



The major system changes considered in this study include the following:

- The East West Tie expansion, which came into service in 2022, adding two 230 kV circuits between the Wawa and Lakehead transformer stations (TS).
- The Lakehead C8 condenser End of Life (EOL) replacement.
- The Waasigan transmission project, which will add a double-circuit 230 kV line between Lakehead TS and Mackenzie TS (Phase 1 of the project) and a single-circuit 230 kV line between Mackenzie TS and Dryden TS (Phase 2). Phase 1 is targeted to be completed at the end of 2025 and Phase 2 is expected to be in service by the end of 2027.
- The Northeast Bulk Plan, which recommended a new single-circuit 500 kV line between Hanmer TS and Mississagi TS, and a double-circuit 230 kV line between Mississagi TS and Third line TS (targeted to be in service by 2029), and a single-circuit 230 kV line (built to 500 kV standard) between Wawa TS and Porcupine TS (targeted to be in service by 2030).

This study identifies reactive requirements to incorporate the above system reinforcements. It does not cover additional reactive needs that may emerge if demand growth exceeds the forecasts considered in this study, or if additional system reinforcements are recommended. Further study will be undertaken as additional changes occur in northern Ontario.

This study also addresses existing operational challenges with voltage control in northern Ontario today. Control Room operators rely heavily on generators providing RSVC (Reactive Support and Voltage Control) services to manage system voltages yet still frequently struggle to maintain voltages within acceptable limits set out in the IESO Market Rules and System Control Orders. Continuing reliance on generating units for voltage support also places additional wear and tear on the units. To address these concerns, this study also identifies requirements and makes recommendations for investments to improve operability for today's system.

1.2 Scope of Study

The Northern Voltage study analyzes the Northeast and Northwest Ontario electricity systems over a 20-year time horizon, from 2023-2042. To represent expected timeframes for development of new planned transmission lines, this study examined four "snapshots" in time:

- **2023**, representing today's system, to assess existing voltage control needs;
- **2025**, representing the system following the integration of phase 1 of the Waasigan project (in 2025);
- **2029**, representing the system after the integration of phase 2 of the Waasigan project (in 2027) and the Northeast Bulk reinforcements between Hanmer and Third Line (in 2029); and
- **2042**, representing the system after the Porcupine x Wawa line comes in service (in 2030) and reflecting forecast load growth to 2042.

This study primarily focuses on high voltage needs, as current operational challenges relate to managing high voltages, and the Waasigan project and the Northeast Bulk Plan are expected to exacerbate these challenges during light load conditions.[5]

For the 2029 and 2042 cases, this study also examines peak demand conditions in order to confirm the capacitive needs that were identified in the Northeast Bulk Plan and recommend the optimal locations and sizes of devices to address these needs.

The transmission assumptions for each timeframe are summarized as follows:

<u>2023 System</u>:

1. Porcupine SVC Out of Service (O/S) due to a long-term forced outage
2. East West Tie expansion in service

[5] Note that if substantial demand growth occurs in the Northwest system, additional dynamic reactive compensation may be needed. However, as the location and size of this need will depend on the extent and location of demand growth, which at this time is highly uncertain, this has been determined to be out of scope for this study. As more information becomes available on development in the Northwest, further study will be undertaken.

3. Replacement of Lakehead C8 condenser with STATCOM rated at +60/-40 Mvar due to it reaching its end of life.[6]

2025 System:

All assumptions for the 2023 system, plus:

4. Waasigan Phase 1 In Service (I/S)
5. All recommendations in this report for today's system (2023) in service[7]

2029 System:

All assumptions for the 2025 system, plus:

6. Restoration of Porcupine SVC to original specifications
7. Waasigan Phase 2 I/S
8. Hanmer X Mississagi 500 kV line I/S
9. Mississagi to Third line 2x230 kV lines I/S
10. All recommendations in this report for the 2025 system in service

2042 System:

All assumptions for the 2029 system, plus:

11. Porcupine X Wawa 500 kV line I/S and operated at 230 kV
12. Forecast electricity demand growth to 2042
13. All recommendations in this report for the 2029 system in service

[6] Note that while the new device is not expected to come into service until 2027, its like-for-similar replacement was assumed in this study due to an earlier recommendation.

[7] This is for study purposes and it is understood that the recommended solutions may come in service after 2025.

2. Major Assumptions

2.1 Demand Assumptions

Light Load Assumptions

In order to assess high voltage issues, light load scenarios were studied for all four timeframes.[8] Table 2 shows the minimum demand assumptions used in the light load cases and compares them to the 2022 APO and actual historical Ontario demand.

Table 2 | System Demand Assumptions for Light Load Cases

Zone	Minimum Demand Assumption used in Study (MW)	Reference[9]	Reference Minimum Demand (MW)
Northeast	820	2022 APO for year 2025	860
Northwest	250	2022 APO for year 2025	360
Ontario	10,230	2021 Ontario Demand	10,400

The demand in the Northeast and Northwest zones was assumed to be slightly less than the forecast minimum in the 2022 APO to account for minimum transfer flows on major transmission interfaces. Similarly, the Ontario demand was assumed to be slightly less than the 2021 minimum demand to ensure the system is adequately stressed.

Peak Demand Assumptions

Reactive requirements considering peak demand conditions were studied for the 2029 and 2042 snapshots. The peak demand forecasts used in this study (as shown in Table 3) are consistent with the 2022 APO[10] Peak Demand Outlook. The Northeast peak demand forecasts also align with the "Potential Growth Scenario" in the Northeast Bulk Plan[11].

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[8] Sensitivity analysis were performed to determine the scenario that will have the lowest transfer flow on the bulk system.

[9] The study used the historical demand information as the reference to assume the minimum demand for Ontario. While the historical data doesn't break down into planning zones, the APO zonal demand forecast information is used as a reference for Northeast and Northwest zones.

[10] The published plan can be found at https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[11] The published plan can be found at https://www.ieso.ca/en/Get-Involved/Regional-Planning/Northeast-Ontario/bulk-planning

Table 3 | Zonal Demand Assumptions for Peak Demand Cases (MW)

	2025	2029	2042
Northeast (MW)	2129	2572	2762
Northwest (MW)	810	856	927

2.2 Generation Assumptions

To develop local hydroelectric generation assumptions for the peak demand scenarios, the 98% dependable hydroelectric capacities for the Northeast and Northwest zones were developed using historical water flow data which was then converted to daily available power for each zone. The resulting 98% dependable capacity in each zone is shown in Table 4. These zonal dependable capacities were then allocated to individual generation units, up to their maximum output level, to achieve a total output matching the hydro assumption for each zone. Units not needed to maintain this capacity were kept out of service to not overestimate the available voltage control.

For the light load scenarios, hydroelectric generation was adjusted as needed to achieve interface flows as close to zero as possible, to assess high voltages caused by lightly loaded transmission lines.

Table 4 | Northern Hydro Generation Assumptions for Peak Scenarios

Zone	Hydro Assumptions based on 98% Dependable Levels (MW)
Northeast	933
Northwest	427

2.3 Major Transmission Interface Flows

Transmission interfaces are defined as one or more transmission circuits connecting two sub-systems of the IESO-controlled grid. Since voltages in northern Ontario are driven largely by interface flows, this study took the approach of establishing flows across several key interfaces to study the impacts on voltages.

It should be noted that with addition of planned transmission reinforcements (i.e., the Waasigan project and Northeast Bulk Plan recommendations), the definitions of key interfaces are expected to change, and new interfaces may be identified. For this study, the existing interfaces were monitored, adjusting them to include future planned parallel circuits as appropriate.

3. Criteria and Methodology

3.1 Criteria

This study was conducted in accordance with the following planning criteria:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"),
- Northeast Power Coordinating Council ("NPCC") Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" ("Directory #1") where applicable, and
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

3.2 Study Methodology

The study was performed to ensure compliance with the above planning criteria. Where post-contingency voltage violations were observed, reactive compensation devices were sized and placed at strategic locations where the voltage violations were most severe. Additionally, transient analysis and operability of the reactive devices were considered when identifying whether static or dynamic reactive support would be required.

For analyis of high voltages, this study applied operational instructions allowing higher post-contingency maximimum voltages that were introduced since ORTAC was last updated. Appendix 1 provides details of the relevant voltage criteria applied in this study.

Recognizing that there are limited actions that can be taken to manage high voltages once available reactive control devices have all been deployed, and that operating above maximum allowable voltages can damage transmission and customer equipment, the IESO took a conservative approach in its contingency assessment for the high voltage cases. Based on feedback received from Operations staff, who frequently need to manage the system with multiple reactive elements out of service due to planned and forced outages, an additional critical reactive compensation device was assumed to be on planned outage in each of the Northwest and Northeast systems prior to simulating the required N-1-1 contingencies specified by ORTAC. Specifically, in the Northwest, Lakehead R1, the largest reactor in the area, was assumed to be unavailable, and in the Northeast, the Porcupine SVC was assumed to be unavailable. This was intended to reflect operational challenges faced by Control Room staff based on historical frequency and duration of outages to reactive devices in the North combined with the highly voltage-sensitive nature of the systems in Northeast and Northwest Ontario, which are characterized by lower demand density than southern Ontario and long, often lightly loaded circuits. The conservative approach adopted for this study is specifically to address the above issues and is not intended to be replicated in other parts of the system or in future planning studies.

The studied contingencies are in accordance with Planning Events P0-P7 listed in the North American Electric Reliability Corporation ("NERC") standard TPL-001-4. For BPS elements, contingencies are in accordance with Category I and II Contingency Events listed in the Northeast Power Coordinating Council ("NPCC") Directory #1.

All elements within or connecting to the Northeast and Northwest zones were monitored.

3.3 Options Considered

To address the identified voltage issues, the study investigated four types of reactive devices commonly used for voltage support: static shunts (capacitors or reactors), static VAR compensators (SVCs), static synchronous compensators (STATCOMs) and Synchronous Condenser (SC).

4. Study Findings

4.1 2023 System—Today's Operational Challenges

Northwest

The existing condenser C8 at Lakehead TS is approaching End-of-Life (EOL). A separate planning study was conducted in 2021 by the IESO at Hydro One's request, prior to the Northern Voltage Study being initiated. The Lakehead C8 EOL replacement study explored the opportunity to right size the EOL replacement for the condenser C8, given expected future system conditions, reactive power requirements and cost of replacement. Without the Lakehead C8, the study observed high voltage issues at Lakehead 230 kV, Mackenzie 230 kV and other stations in the Northwest. The IESO recommended the condenser C8 at Lakehead TS to be replaced with a FACTS device (e.g. SVC or STATCOM) rated at +60/-40 Mvar. See Appendix 2 for more details.

As described in section 3.2, based on operational experience and historical outages in this region, it was determined that the Lakehead R1 would be assumed unavailable prior to application of planning criteria in the Northwest.

The worst contingency observed is one of the Lakehead transformers out of service, followed by the loss of the companion Lakehead transformer. This condition essentially results in the loss of both SVCs (STATCOMs) at Lakehead TS as they are connected to the tertiary windings of the transformers. Study results indicated that additional reactive compensation is required today to manage high voltages in the Northwest under this scenario. Therefore, the study recommends one new reactor (with the size of 40 Mvar) to be added to Lakehead TS. The voltage analysis results are shown in Table 5.

Table 5 | Voltage Results with Proposed Reactor

Condition	Limiting Contingency	Monitored Element	Voltage (kV) (without the proposed reactor)	Voltage (kV) (with the proposed reactor)
Light load, Lakehead R1 O/S and Lakehead transformer O/S	Loss of the companion Lakehead transformer	Lakehead 230 kV	270	259
Light load, Lakehead R1 O/S and Lakehead transformer O/S	Loss of the companion Lakehead transformer	MacKenzie 230 kV	258	252

This study further analysed the impact of switching the existing 125 Mvar reactor R1 at Lakehead TS on voltages in the area. IESO control room operators report that the large size of this reactor limits operational flexibility. Not only do they observe large voltage changes when switching the Lakehead R1, the reactor's large size has necessitated system operating limits that require depressing the voltage at

Lakehead pre-contingency when it is in service to avoid excessively high voltages post-contingency. The size of this reactor becomes even more problematic during outage conditions, to the point that it often cannot be used at all.

To replicate these reports, the voltage changes upon switching the Lakehead R1 were assessed in this study. Under all-in-service conditions, a voltage change of less than 4% (or ~9 kV) was observed. Under N-1 conditions, the voltage change was approximately 5.5% (~13 kV) and under N-1-1 conditions, a voltage change of over 6% (~14 kV) was observed.

If the Lakehead R1 was replaced with two 40 Mvar reactors, it would provide better operational flexibility in switching the reactors and managing outages to other equipment while still providing adequate reactive capability in the area. Therefore, the IESO recommends replacing the existing R1 with two new 40 Mvar reactors. The existing 125 Mvar reactor can be redeployed to another station in the system.

Northeast

As described in section 3.2, based on operational experience and historical outages in this region, it was determined that the Porcupine SVC would be assumed unavailable prior to application of planning criteria in the Northeast.[12]

The study observed high voltage issues on the Porcupine 500 kV and 230 kV buses as shown in Table 6.

Table 6 | High Voltage Violations - Northeast

Condition	Limiting Contingency	Limit Type	Monitored Element	Voltage (kV)
Light Load Porcupine SVC O/S	Pre-contingency	High Voltage	Porcupine 230 kV	250
Light Load Porcupine SVC O/S	Pre-contingency	High Voltage	Porcupine 500 kV	555

The study found that the addition of two shunt reactors (60 Mvar each) at Porcupine TS would help mitigate the high voltage issues. The voltage analysis results are shown in Table 7.

Table 7 | Voltage Results with Proposed Reactors

Condition	Limiting Contingency	Monitored Element	Voltage (kV) (with the proposed reactors)
Light Load Porcupine SVC O/S	Pre-contingency	Porcupine 230 kV	246

[12] The existing Porcupine SVC failed in 2021 and has been unavailable since then. The transmitter is working to fix the damaged equipment and address the identified root cause issues and intends to bring it back in service in 2026.

Light Load Porcupine SVC O/S	Pre-contingency	Porcupine 500 kV	545

Based on information provided by the transmitter, all four transformers at Porcupine have tertiary windings that can accommodate reactive devices, however the option of connecting two 28 kV shunt reactors (60 Mvar each) to the tertiary windings of autotransformers T7 and T8 would be preferred. This is because the tertiary windings on the T5 and T6 are rated at 50 MVA or less, limiting the reactor size that can be accommodated.

4.2 2025 System—Integration of Waasigan Phase 1

The 2025 snapshot captures the incorporation of Phase 1 of the Waasigan project. The reactive requirements identified for the today's system above were assumed to be in service for this time slice. No incremental needs emerge in the Northeast system in 2025.

While the Waasigan project is designed to reinforce transmission supply in the region, the additional circuits are expected to inject a significant amount of reactive power due to line charging during light load conditions. With the Waasigan phase 1 project in service, high voltage issues in the Northwest were observed under the light load case. These issues are summarized in Table 8.

Table 8 | 2025 Voltage Results after Waasigan Phase 1

Condition	Limiting Contingency	Monitored Element	Voltage (kV) (without the proposed reactors)
Light load, Lakehead R1 O/S and Lakehead transformer O/S	Loss of the companion Lakehead transformer	Lakehead 230 kV	287
Light load, Lakehead R1 O/S and Lakehead transformer O/S	Loss of the companion Lakehead transformer	MacKenzie 230 kV	280

The study recommends a minimum of 120 Mvar of additional reactive absorption to maintain voltages below operational maximum voltage criteria. In addition to the 40 Mvar reactor recommended in section 4.1, it is recommended that 80 Mvar reactive compensation be installed at Mackenzie TS to support the Waasigan project. Due to the operational issues associated with larger sized reactors in the Northwest, it is recommended that the additional reactors all be sized at 40 Mvar. Table 9 summarizes the findings of the reactive compensation analysis.

Table 9 | 2025 Northwest System Voltage Results (with proposed reactors)

Scenario	Reactive Requirement	Post-contingency voltage (kV) @Lakehead 220	Post-contingency voltage (kV) @Mackenzie 220	Post-contingency voltage (kV) @Dryden 220
Waasigan Phase 1	2x40 Mvar reactors at Mackenzie	256[13]	248	241

4.3 2029 System—Integration of Waasigan Phase 2 and Reinforcements from Sudbury to Sault Ste. Marie

The 2029 snapshot includes Phase 2 of the Waasigan project and the reinforcements between Sudbury and Sault Ste. Marie recommended in the Northeast Bulk Plan (i.e., a new single-circuit 500 kV line from Hanmer TS to Mississagi TS and a new double-circuit 230 kV line between Mississagi TS and Third Line TS). The reactive requirements identified above for the 2023 and 2025 system were assumed to be in service for this time slice.

Northwest

With the Waasigan phase 2 project in service and the reactors that were proposed in this study for the 2023 and 2025 system, no additional high voltage issues in the Northwest were observed under the light load case. These study results are summarized in Table 10.

Table 10 | 2029 Voltage Results with Waasigan Phase 2

Condition	Contingency	Post-contingency voltage (kV) @Lakehead 220	Post-contingency voltage (kV) @Mackenzie 220	Post-contingency voltage (kV) @Dryden 220
Light load, Lakehead R1 O/S and Lakehead transformer O/S	Loss of the companion Lakehead transformer	259[14]	252	247

Northeast

High Voltage Issues

[13] For post-contingency analysis, increased maximum voltages up to 5% above ORTAC maximums were assumed to be acceptable, consistent with IESO operating practice, so long as control actions are available to reduce voltages down to ORTAC maximums within 30 min.

[14] For post-contingency analysis, increased maximum voltages up to 5% above ORTAC maximums were assumed to be acceptable, consistent with IESO operating practice, so long as control actions are available to reduce voltages down to ORTAC maximums within 30 min.

With the Northeast Bulk reinforcements between Hanmer TS and Third Line TS in service, the study observed high voltage issues under light load conditions. The study results are summarized in

Table 11.

Table 11 | 2029 Northeast System Voltage Violations (High Voltages)

Condition	Limiting Contingency	Limit Type	Limiting Element	Voltage (kV)
Light Load	Pre-contingency	High Voltage	Mississagi 500 kV	556
Light Load	Pre-contingency	High Voltage	Mississagi 230 kV	250
Light Load Hanmer R6 or R9 O/S	Pre-contingency	High Voltage	Mississagi 500 kV	566
Light Load Hanmer R6 or R9 O/S	Pre-contingency	High Voltage	Mississagi 230 kV	255
Light Load Hanmer R6 O/S	Hanmer T9	High Voltage	Mississagi 500 kV	576

Low Voltage and Voltage Drop Issues

As the new Porcupine TS to Wawa TS transmission line will not yet be in service in this time slice, the study observed post-contingency low voltage and voltage deviation issues under peak load conditions. The loss of new 500 kV circuit from Hammer TS to Mississagi TS would be the most limiting contingency.

The study results are summarized in Table 12.

Table 12 | 2029 Northeast System Voltage Violations (Low Voltages and Deviation)

Condition	Limiting Contingency	Limit Type	Limiting Element	Pre-Contingency Voltage (kV)	Post-Contingency Voltage (kV)	Voltage Change (%)
Peak Load	New 500 kV circuit from Hammer TS to Mississagi TS	Low Voltage and Voltage Deviation	Third Line 230 kV	233	207	-11.2
Peak Load	New 500 kV circuit from Hammer TS to Mississagi TS	Voltage Deviation	Algoma 230 kV	246	215	-12.8

Peak Load	New 500 kV circuit from Hammer TS to Mississagi TS	Voltage Deviation	Mississagi 230 kV	239	211	-11.9

Options to Address the High Voltage Issues

To address the high voltage needs, two static shunt options were assessed:

- Option 1: adding a 120 Mvar line reactor connecting to the new 500 kV line from Hanmer TS to Mississagi TS.
- Option 2: adding two tertiary reactors (60 Mvar each) connecting to the new auto-transformers at Mississagi TS.

The technical performance of these two options were found to be comparable. Option 1 offers the advantage of automatically tripping the reactor in response to the line contingencies providing immediate voltage support during peak demand conditions. Option 2 would provide greater operational flexibility, however not placing the reactive support on the line would necessitate a reactor arming scheme for the 500 kV line contingency. Considering the above, Option 1 is recommended. The voltage analysis results with the proposed reactor at Mississagi are shown in Table 13.

Table 13 | 2029 Voltage Results (with proposed reactor at Mississagi TS)

Condition	Limiting Contingency	Monitored Element	Voltage (kV) (with the proposed reactor)
Light Load	Pre-contingency	Mississagi 500 kV	539
Light Load	Pre-contingency	Mississagi 230 kV	242
Light Load Hanmer R6 or R9 O/S	Pre-contingency	Mississagi 500 kV	545
Light Load Hanmer R6 or R9 O/S	Pre-contingency	Mississagi 230 kV	245
Light Load Hanmer R6 O/S	Hanmer T9	Mississagi 500 kV	549

Options to Address the Low Voltage Issues

To address the low voltage and voltage drop issues, both static and dynamic reactive devices were considered. The study found that dynamic reactive support would be the preferred option to improve post-contingency transient voltage performance. Additionally, adding dynamic reactive support would improve operability and avoid the need for additional complicated switching schemes involving the arming and selection of remote critical contingencies. The dynamic reactive support would also assist with voltage control under normal operations, reducing the impact of load fluctuations.

The study also explored the option of enhancing the existing adjacent generation facilities (e.g. Aubrey Falls GS and Wells GS) to expand their reactive capabilities to provide additional voltage support. However, due to limitations on the additional range that could be provided, they would not be able to provide the necessary reactive power to fulfill the requirements.

In order to find the optimal locations, the study tested options of adding reactive support at various locations including Third Line TS, Mississagi TS, Algoma TS, Hanmer TS and Wawa TS. The technical performance, physical feasibility and cost estimates of these options are summarized in Table 14. For locations with limited additional space or where substantial station reconfiguration would be required, no further consideration was given as the additional associated cost is highly uncertain and is expected to be substantial, and sufficient effective locations not requiring substantial station work were identified to meet the needs.

Table 14 | Options Evaluation for Dynamic Reactive Devices - Locations

Location	Technical Performance	Physical Feasibility	Estimated Cost (M$)
Third Line TS 230 kV	Able to meet the requirement. Worst contingency is the loss of new Hanmer-Mississagi 500 kV circuit in 2029 system. **Benefit:** effective voltage support for local 230 kV system.	There is no room left at the station (based on current and/or planned development)	No further consideration
Third Line TS 115 kV	Able to meet the requirement. **Benefit:** effective voltage support for local 115 kV system.	There may be room at the station (based on current and/or planned development) but substantial re-configuration would be required	No further consideration
Mississagi TS 230 kV	Able to meet the requirement. **Benefit:** effective dynamic voltage control for different MISSW levels.	There is sufficient room at the station	50

Wawa TS 230 kV	Able to meet the requirement. **Benefit:** dynamic voltage control for different EWT levels.	There is no room left at the station (based on current and/or planned development)	No further consideration
Hanmer TS 230 kV	Not effective for the 2029 system post the worst contingency of Hanmer-Mississagi 500 kV circuit. **Benefit:** opportunity to set up control system coordinating with the existing capacitors and reactors at Hanmer TS.	There is room at the station with some relocation of existing equipment required	>50
Algoma TS 230 kV	Able to meet the requirement. **Benefit:** opportunity to set up the control system coordinating with the existing capacitor and optimize the existing facility usage.	There is sufficient room at the station	50

Based on the above evaluation results, options involving Third Line TS and Wawa TS were ruled out due to concerns over their physical feasibility. The Hanmer TS option was ruled out as it would not meet the need. Balancing technical performance and physical feasibility, Mississagi TS and Algoma TS were selected as the preferred location options.

To enable adequate voltage support during planned or forced outages to the proposed reactive equipment, it is prudent to recommend adding two smaller-sized devices rather than one large device. Opting for devices at multiple locations ensures a more distributed and reliable setup and reduce the impact of outages. To meet the identified need while maintaining flexibility to withstand outages, two ±100 Mvar STATCOM devices are recommended with one located at Mississagi TS and the other one located at Algoma TS. The recommended STATCOMs will enable the full increase in transfer capability indicated in the Northeast Bulk plan.

The study results with the proposed devices at Mississagi TS and Algoma TS are summarized in Table 15.

Table 15 | 2029 Voltage Results (with proposed STATCOMs)

Condition	Limiting Contingency	Monitored Element	Pre-Contingency Voltage (kV)	Post-Contingency Voltage (kV)	Voltage Change (%)
Peak Load	New 500 kV circuit from Hammer TS to Mississagi TS	Third Line 230 kV	233	233	-0.2

Peak Load	New 500 kV circuit from Hammer TS to Mississagi TS	Algoma 230 kV	246	242	-1.6
Peak Load	New 500 kV circuit from Hammer TS to Mississagi TS	Mississagi 230 kV	239	238	-0.4

4.4 2042 System—Integration of the Porcupine to Wawa Line and Demand Growth

The 2042 snapshot includes the new 230 kV circuit from Porcupine TS to Wawa TS recommended in the Northeast bulk plan as well as forecast load growth to 2042. The study tested the system with the reactive support that was proposed in this study for the 2023, 2025 and 2029 system, and voltages were observed to be able to meet the criteria.

The study found that the proposed STATCOMs would continue to be needed to provide real-time voltage regulation and more flexible and effective capabilities in managing voltage stability, especially during periods of high load variability and system outages and contingencies.

As a sensitivity analysis, the study assessed the 2042 system with the "High Growth Scenario" included in the Northeast Bulk Plan. The proposed STATCOMs can effectively control the voltages at Wawa TS to above 80% of nominal voltage following the P502X contingency and meet the ORTAC transient voltage criteria. Therefore, the proposed dynamic reactive devices would be needed to ensure system voltage stability in the long term, under a higher growth scenario.

5. Recommendations

This section summarizes the recommendations based on the results and findings from this study. Table 16, Table 17 and Table 18 summarize the reactive compensation requirements for the 2023, 2025 and 2029 time slices, respectively. No additional recommendations are needed for the 2042 snapshot. For the 2023 requirements, it is recognized that the recommendations will take time to implement. Some of these recommendations have already begun implementation, as noted in the comments in Table 16. Timelines for implementing all the recommendations in this study will be provided to the transmitter in a separate communication.

Table 16 | 2023 System Reactive Compensation Recommendations

Device Type	Location	Reactive Rating (Mvar)	Capacitive Rating (Mvar)	Comments
Shunt Reactor	Lakehead TS	-40	0	Connected at the 230 kV station as per the SIA requirement for Waasigan project
Shunt Reactor	Lakehead TS	2 × -40	0	Connected at the 230 kV level to replace the existing R1. The transmitter will explore the opportunity to re-use the existing Lakehead R1 elsewhere in the system.
Shunt Reactors	Porcupine TS	2 × -60	0	Two tertiary reactors (60 Mvar each) connecting to T7 and T8

Table 17 | 2025 System Reactive Compensation Recommendations

Device Type	Location	Reactive Rating (Mvar)	Capacitive Rating (Mvar)	Comments
Shunt Reactors	Mackenzie TS	2 x -40	0	Connected at the 230 kV station as per the SIA requirement for Waasigan project

Table 18 | 2029 System Reactive Compensation Recommendations

Device	Location	Reactive Rating (Mvar)	Capacitive Rating (Mvar)	Comments
Line Reactor	Mississagi TS end of the new 500 kV circuit Hanmer - Mississagi	-120[15]	0	The line reactor will be carefully sized with the line charging capacitance during the implementation process.
STATCOM	Mississagi TS	-100	100	Dynamic reactive capability is needed to improve post-contingency transient voltage performance; Fast-acting capability can also benefit the normal operation voltage control to reduce the impact from load fluctuations.
STATCOM	Algoma TS	-100	100	The future control system can be set up to coordinate the SVC or STATCOM with the existing capacitor and optimize the usage of existing assets. It can also benefit the normal operation voltage control to reduce the impact from load fluctuations.

[15] The size of 120 Mvar rated at 500 kV is approximate and the exact size will be confirmed by Transmitter.

Appendix 1 – Relevant Criteria

Thermal loading, voltage performance and power transfer capability are relevant to this study and the reference sections in ORTAC are summarized below. For post-contingency analysis, increased maximum voltages up to 5% above ORTAC maximums were assumed to be acceptable, consistent with IESO operating practice, so long as control actions are available to reduce voltages down to ORTAC maximums within 30 min.

Voltage Criteria (section 4.2, 4.3 4.4 and 4.5 of ORTAC)

Under pre-contingency conditions with all facilities in service, or with a critical element(s) out of service after permissible control actions and with loads modeled as constant MVA, the IESO-controlled grid is to be capable of achieving acceptable system voltages (minimum, maximum and deviations) as outlined in the table below.

Table A1 | Voltage Limit Criteria

Applicable Limit	Nominal Bus Voltage (kV)		
	500	**230**	**115**
Pre-contingency Maximum Voltage	550	250	127**
Pre-contingency Minimum Voltage	490	220	113
Post-contingency Maximum Voltage	550	250	127
Post-contingency Minimum Voltage	470	207	108
Post-contingency Maximum deviation	10%	10%	10%

Notes:

* Transmission equipment must remain in service, and not automatically trip, for voltages up to 5% above the maximum continuous rating, for up to 30 minutes, to allow the system to be re-dispatched to return voltages within their normal range.

**In Northern Ontario, individual stations may have 115 kV maximum voltages that exceed 127 kV, up to 132 kV.

Steady State Voltage Stability

Steady state stability is the ability of the IESO-controlled grid to remain in synchronism during relatively slow or normal load or generation changes and to damp out oscillations caused by such changes. The following checks are carried out to ensure system voltage stability for both the pre-contingency period and the steady state post-contingency period:

- Properly converged pre- and post-contingency power flows are to be obtained with the critical parameter increased up to 10% with typical generation as applicable;

- All of the properly converged cases obtained must represent stable operating points. This is to be determined for each case by carrying out P-V analysis at all critical buses to verify that for each bus the operating point demonstrates acceptable margin on the power transfer as shown in the following section; and
- The damping factor must be acceptable. The P-V curves and transient analysis are used to identify stability limits and dynamic voltage performance simulations.
- The collapse point of a P-V curve, or voltage instability point, is the point where the slope of the P-V curve is vertical. The maximum acceptable pre-contingency power transfer must be the lesser of:
- a pre-contingency power transfer (point a) that is 10% lower than the voltage instability point of the pre-contingency P-V curve, and
- a pre-contingency transfer that results in a post-contingency power flow (point b) that is 5% lower than the voltage instability point of the post-contingency curve

Appendix 2 – Lakehead C8 Condenser Replacement Study

In 2021, the IESO undertook a study to assess and evaluate options for the End-of-Life (EOL) replacement of the C8 condenser and associated protections and control equipment at Lakehead Transformer Station (TS). This planning study explored the opportunity to right size the EOL replacement for the condenser C8, which is rated at +60/-20 Mvar, given the expected future system conditions, reactive power requirements and cost of replacement.

Hydro One Networks Inc. (HONI) had already replaced the other synchronous condenser at Lakehead, C7, which was connected to Lakehead T7, with a Static Var Compensator (SVC) in 2009. HONI asked for IESO's assessment and recommendation on whether a replacement of the C8 condenser with a like-for-like FACTS device would be sufficient to meet reactive power requirements at Lakehead TS.

This study assessed the static and dynamic Var requirements in the Lakehead area through:

- Review of findings and recommendations in previous engineering studies (i.e., feasibility study and SIAs) for the new EWT to determine their applicability when considering updated planning assumptions.
- Review of the findings from the recently completed limit study for the new East West Tie expansion and assessing the impact of the potential replacement options for condenser C8, for low demand and peak load scenarios; and,
- Assessment of the transient response of the SVC compared to a like-for-like synchronous condenser.

The two options considered for the Lakehead C8 condenser were Hydro One's base sustainment option (+60/-40 Mvar FACTS device) and the option recommended as part of the previous SIAs for higher transfers on the EWT (±100 Mvar SVC). Load flow analysis was conducted with a +60/-40 Mvar SVC and a ±100 Mvar SVC for the lowest demand scenario and the worst contingency, which was the loss of the new 125 Mvar reactor. Study results showed that replacing the C8 with an SVC rated at ±100 Mvar is more effective in keeping the post contingency voltages under their prescribed maximums at Lakehead TS and Marathon TS, as compared to a like-for-like SVC rated at +60/-40 Mvar. However, this issue is a bulk transmission system issue that spreads across the entire northwest and northeast corridor and warrants a broader solution, given all of the future reinforcements in the regions (i.e., the Waasigan Transmission Line and the reinforcements resulting from the Northeast Bulk Plan).

HONI's cost estimate for a FACTS device rated at +60/-40 Mvar was $25M whereas a ±100 Mvar FACTS device was estimated to cost $75M. Based on the study results, options analysis, and the urgent need for EOL replacement, it was determined that it was prudent to proceed with replacing the Lakehead C8 with the base sustainment option (i.e., the +60/-40 Mvar device on the tertiary winding of T8), and to continue to review voltage needs in a broader study of northern Ontario reactive requirements, which has culminated in this report.

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