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Joanne Richardson
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

July 31, 2017

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON
M4P 1E4

Dear Ms. Walli:

EB-2017-0194 – Hydro One Networks Inc.'s Section 92 – East West Tie Station Project – Application and Evidence

Please find attached two copies of Hydro One Networks Inc.'s ("Hydro One") Application and Evidence in support of an Application pursuant to Section 92 of the Ontario Energy Board Act for an Order or Orders granting leave to upgrade existing transmission station facilities in the Districts of Thunder Bay and Algoma.

Hydro One's contacts for service of documents associated with this Application are listed in Exhibit B, Tab 1, Schedule 1.

An electronic copy of the complete application has been filed using the Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

Attach

Exhibit List

Exh	Tab	Schedule	Attachment	Contents
A				
	1	1		Exhibit List
B				
	1	1		Application
	1	1	1	Government Order in Council
	2	1		Project Overview
	2	1	1	IESO Third Update Report - Assessment of the Rationale for the East-West Tie Expansion
	2	1	2	Wawa TS-Existing and Proposed Diagram
	2	1	3	Marathon TS- Existing and Proposed Diagram
	2	1	4	Lakehead TS- Existing and Proposed Diagram
	3	1		Evidence In Support of Need
	3	2		IESO Need Evidence
	4	1		Project Classification and Categorization
	5	1		Cost Benefit Analysis and Options
	6	1		Quantitative Benefits
	7	1		Apportioning Project Costs and Risks
	8	1		Network Reinforcement

ONTARIO ENERGY BOARD

In the matter of the *Ontario Energy Board Act, 1998*;

And in the matter of an Application by Hydro One Networks Inc. pursuant to s. 92 of the *Act* for an Order or Orders granting leave to upgrade existing transmission station facilities in the Districts of Thunder Bay and Algoma.

And in the matter of an Application by Hydro One Networks Inc. pursuant to s. 97 of the Act for an Order granting approval of the forms of the agreement offered or to be offered to affected landowners

APPLICATION

The Applicant is Hydro One Networks Inc. ("Hydro One"), a subsidiary of Hydro One Inc. The Applicant is an Ontario corporation with its head office in the City of Toronto. Hydro One carries on the business, among other things, of owning and operating transmission facilities within Ontario.

In 2012, the Ontario Energy Board ("the Board") initiated a proceeding to designate an electricity transmitter to undertake the development work for the new East-West Tie Line. In August 2013, Upper Canada Transmission, Inc. [operating as NextBridge Infrastructure ("NextBridge")] was chosen as the proponent to develop the new transmission line. The Ministry of Energy issued an Order in Council (see **Exhibit B, Tab 1, Schedule 1, Attachment 1**) in March 2016 declaring that the East-West Tie Project, with an in-service date of 2020, is needed as a priority project.

NextBridge has filed an application (EB-2017-0182) pursuant to s. 92 of the Act, to construct the new East-West Tie Line. Hydro One is now filing this Application pursuant to s. 92 of the Act to perform the necessary station work to connect the new East-West Tie Line, as Hydro One needs to upgrade its existing transmission station facilities at Wawa TS, Marathon TS and Lakehead TS. NextBridge, the IESO and Hydro One have worked together to design a transmission solution to meet the transmission needs in northwestern Ontario by 2020, and both the NextBridge application and Hydro One's Application are supported by the IESO.

Over time, different publications and materials have used various terms to refer to components required to bring the proposed new East-West Tie Transmission Project into service. For the purposes of this Application and for the ease of the reader, except where otherwise defined, the term "EWT Line Project" (or "New EWT Line" or "East-West Tie Line Project") will hereinafter be used to mean the transmission line consisting of conductors, insulators, structures and wires, running from Lakehead Transformer Station (TS) to Marathon TS and from Marathon TS to Wawa TS, as further defined in EB-2017-0182. The term "EWT Station Project" (or "East-West Tie Station Project" or "East-West Tie Station") will refer to the connection of the New EWT Line to the stations and any upgrades at the stations, as further defined in this Application. The terms "East-West Tie Project" (or "East-West Tie Expansion" or "New EWT" or "East West Tie") will be used in the evidence to refer to both the EWT Line Project and the EWT Station Project.

This Application is also for approval of the forms of the agreement offered or to be offered to affected landowners, pursuant to s. 97 of the Act.

The proposed EWT Station Project is required to incorporate the New EWT Line Project with sufficient transfer capability to meet the growing electricity demand in Northwest Ontario, while meeting the performance requirements of the TPL-001-4 standard of NERC (in particular, respecting double-circuit and breaker-failure contingencies) and the

Ontario Resource and Transmission Assessment Criteria ("ORTAC") of the IESO. See **Exhibit B, Tab 3, Schedules 1 and 2** for more information on the need for this project.

The proposed in-service date of the EWT Station Project is November, 2020 assuming a construction commencement date of May, 2018. A project schedule is provided at **Exhibit B, Tab 11, Schedule 1**.

The proposed EWT Station Project work includes:

- Installing new facilities at each of the three terminal stations, Wawa TS, Marathon TS, and Lakehead TS, for connecting the new 230 kV circuits of the EWT Line Project;
- Reconfiguring the existing facilities at Wawa TS and Marathon TS and installing new facilities at the three terminal stations to enable 450 MW east-west power transfer (in the interim period) while respecting the NERC and ORTAC criteria and bringing the station layouts in compliance with the ORTAC guidelines;
- Installing additional reactive compensation at Lakehead TS to mitigate the existing high voltage issue.

New land rights will be required for the station expansion at Marathon TS and Wawa TS. A fee simple purchase of additional lands adjacent to the current properties is required to accommodate the necessary station upgrades. No additional property rights are required at Hydro One's current Lakehead TS station property. Temporary construction rights for access or staging areas may be required at various locations for the duration of the construction period of the EWT Station Project. Further information on land related matter is found at **Exhibit E, Tab 1, Schedule 1**.

The IESO has provided a Final System Impact Assessment ("SIA") Report for Hydro One's proposed modifications to the three terminal transformer stations. The SIA concludes that the Project is expected to have no material adverse impact on the reliability of the integrated power system and that the project is adequate for the targeted westward transfer level of 450 MW across the East-West Tie. A copy of the SIA, including the addendum, is provided as **Exhibit F, Tab 1, Schedule 1, Attachments 1 and 2**.

Hydro One has completed a Customer Impact Assessment ("**CIA**") for the East-West Tie Project in accordance with Hydro One's connection procedures. The results confirm that the East-West Tie Project has relatively small impact on short-circuit levels in the area, has no adverse impact on voltage performance in the area and will improve power supply reliability in the area. A copy of the CIA is provided as **Exhibit G, Tab 1, Schedule 1, Attachment 1**.

The total cost of the EWT Station Project is approximately $157.3 million. The details pertaining to these costs are provided at **Exhibit B, Tab 7, Schedule 1**. Project economics, as filed in **Exhibit B, Tab 9, Schedule 1**, estimate that the EWT Station Project will result in a maximum $.09/kW/month increase in the line network pool rate and a slight increase (0.05%) on the overall average Ontario consumer's electricity bill.

This Application is supported by written evidence which includes details of the Applicant's proposal for the transmission station work. The written evidence is prefiled and may be amended from time to time prior to the Board's final decision on this Application.

Given the information provided in the prefiled evidence, Hydro One submits that the Project is in the public interest. The East-West Tie Project is a Government of Ontario priority project to support expansion of transmission infrastructure in northwestern Ontario. The EWT Station Project is required to connect the proposed EWT Line Project to Ontario's electricity network.

Hydro One is requesting a written hearing, in English for this proceeding. Hydro One requests that a decision on this Application is provided in the first quarter of 2018 to meet the Ministry of Energy's requested in-service date of December 2020.

Hydro One requests that a copy of all documents filed with the Board be served on the Applicant and the Applicant's counsel, as follows:

a) The Applicant:

Eryn MacKinnon
Sr. Regulatory Coordinator
Hydro One Networks Inc.

Mailing Address:

7th Floor, South Tower
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b) The Applicant's counsel:

Michael Engelberg
Assistant General Counsel
Hydro One Networks Inc.

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Ministry of Energy

Office of the Minister

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Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

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Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Received
MAR 11 2016
Office of the Chair
Ontario Energy Board

Ontario

MC-2016-569

MAR 10 2016

Ms Rosemarie LeClair
Chair and Chief Executive Officer
Ontario Energy Board
PO Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms LeClair:

The East-West Tie, identified as a priority project in the 2013 Long-Term Energy Plan, is a cornerstone of this government's policy to support expansion of transmission infrastructure in northwestern Ontario. The East-West Tie continues to be the Independent Electricity System Operator's recommended alternative to maintain a reliable and cost-effective supply of electricity to northwestern Ontario for the long term.

Under the authority of section 96.1(1) of the *Ontario Energy Board Act, 1998*, ("the Act") the Lieutenant Governor in Council made an order declaring that the construction of the East-West Tie transmission line is needed as a priority project. The Order in Council took effect on March 4, 2016 and is attached to this letter.

Please do not hesitate to contact my office with any questions.

Sincerely,

Bob Chiarelli
Minister

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Ontario considers it necessary to expand Ontario's transmission system in order to maintain a reliable and cost-effective supply of electricity in the Province's Northwest, increase operational flexibility, reduce congestion payments and remove a barrier to resource development in the region;

AND WHEREAS Ontario considers the expansion or reinforcement of the electricity transmission network in the area between Wawa and Thunder Bay composed of the high-voltage circuits connecting Wawa TS with Lakehead TS (the "East-West Tie Line Project"), with an in service date of 2020, to be a priority;

AND WHEREAS the Lieutenant Governor in Council may make an order under section 96.1 of the *Ontario Energy Board Act, 1998* (the "Act") declaring that the construction, expansion or reinforcement of an electricity transmission line specified in the order is needed as a priority project;

AND WHEREAS an order under section 96.1 of the Act requires the Ontario Energy Board, in considering an application under section 92 of the Act in respect of the electricity transmission line specified in the order, to accept that the construction, expansion or reinforcement is needed when forming its opinion under section 96 of the Act;

NOW THEREFORE it is hereby declared pursuant to section 96.1 of the Act that the construction of the East-West Tie Line Project is needed as a priority project, and that the present order shall take effect on the day that section 96.1 of the Act comes into force.

Recommended: ______________________
Minister of Energy

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: MAR 0 2 2016
Date

____
Administrator of the Government

O.C./Décret 326/2016

Project Overview Documents

The EWT Station Project will allow the connection of NextBridge's EWT Line Project. Together, the NextBridge project and the Hydro One project complete what is known as the East-West Tie Project. The East-West Tie Project has been identified as a priority in both the Ontario Government's 2010 and 2013 Long-Term Energy Plans and the 2016 Order-in-Council. It will increase the power transfer capability between the Northeast and Northwest regions of Ontario from the current 155-175 MW limit[1] to 450 MW limit and allow the bulk transmission system between Wawa and Thunder Bay to meet the mandatory requirements of the North American Electric Reliability Corporation (NERC) and the Independent Electricity System Operator (IESO).

The EWT Line Project includes a new 230 kV double-circuit transmission line connected between Wawa TS and Marathon TS and a new 230 kV double-circuit transmission line connected between Marathon TS and Lakehead TS. Upper Canada Transmission (operating as NextBridge) was designated by the OEB in 2013 to develop the new transmission lines. Hydro One, as the connecting transmitter, will connect the new transmission lines to Wawa TS, Marathon TS and Lakehead TS. NextBridge has applied separately for leave to construct approval for the line component of the East-West Tie Project. Refer to the NextBridge application (EB-2017-0182) for information on the EWT Line Project.

The Hydro One EWT Station Project, specifically, includes the addition of new facilities and upgrades at three Hydro One transmission stations (TS), Wawa TS, Marathon TS and Lakehead TS, which are located near the cities of Wawa, Marathon and Thunder Bay, respectively. Figure 1 below shows the geographic location of these stations as well as the existing and proposed transmission lines.

[1] The IESO's Third Update Report, attached as Attachment 1 to this exhibit, has specified the current East-West transfer capability as 155 MW in summer and 175 MW in winter.

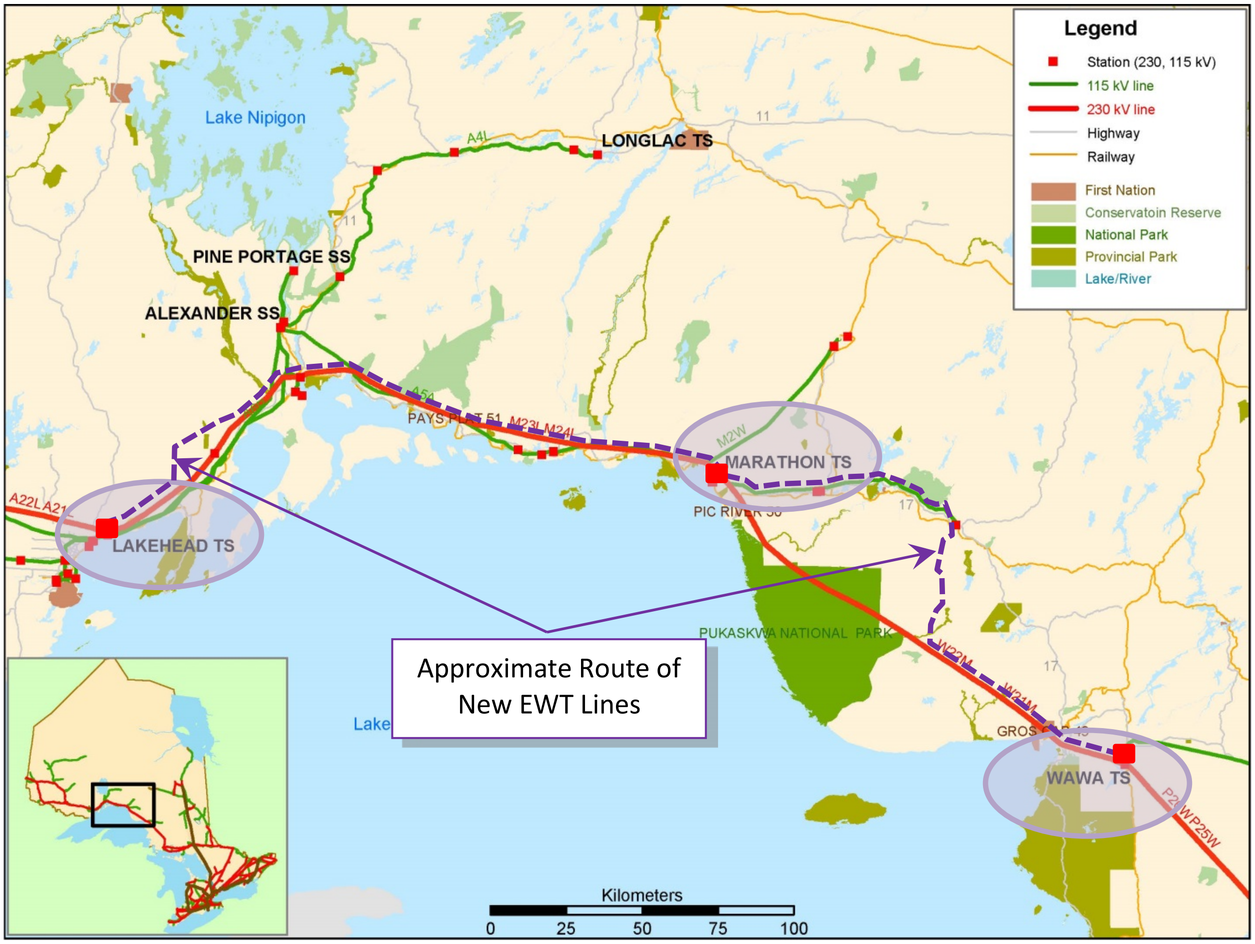

Figure 1: MAP OF GENERAL LOCATION OF EXISTING AND PROPOSED EWT FACILITIES

In addition to connecting the new NextBridge built 230 kV transmission lines at the three terminal stations, Hydro One will perform the following work at its transmission facilities:

- At Wawa Transformer Station
  - Expand the station footprint by approximately 0.5 hectares;
  - Extend the 230 kV buses and add new diameters between them;
  - Upgrade the existing 230 kV buses and diameters;
  - Add new circuit breakers and associated breaker-disconnect switches on the diameters;

- Connect the New EWT Line to the new diameter through line disconnect and ground switches;
- Reconnect the existing transmission lines to new termination points;
- Upgrade the disconnect/ground combination switches for the existing East-West Tie transmission lines; and
- Complete 230 kV protection, control and telecommunication upgrade and expansion, including the relay building.

- At Marathon Transformer Station
  - Expand the station footprint by approximately five hectares;
  - Extend the 230 kV buses and add new diameters between them;
  - Upgrade the existing 230 kV buses and diameters;
  - Add new circuit breakers and associated breaker-disconnect switches on the diameters;
  - Connect the New EWT Line to the new diameters through line disconnect and ground switches;
  - Reconnect the existing transmission lines to new termination points;
  - Add two new 230 kV, 65 Mvar each, three-phase shunt reactors and their switching breakers/switchers, disconnect switches and their associated facilities;
  - Upgrade the disconnect/ground combination switches for the existing East-West Tie transmission lines; and
  - Complete 230 kV protection, control and telecommunication upgrade and expansion, including the relay building.

- At Lakehead TS
  - Extend the 230 kV buses and add a new diameter between them;
  - Upgrade the existing 230 kV buses and diameters;

- Add new circuit breakers, with associated breaker-disconnect switches on the diameters;
- Connect the New EWT Line to the new diameter through line disconnect and ground switches;
- Add a new 230 kV, 125 Mvar three-phase shunt reactor with its switching breaker/switcher, disconnect switch and associated facilities;
- Add a new 230 kV, 125 Mvar three-phase shunt capacitor bank with its series reactor, switching breakers, disconnect switch and associated facilities;
- Upgrade the disconnect/ground combination switches for the existing East-West Tie transmission lines; and
- Complete 230 kV protection, control and telecommunication upgrade and expansion, including the relay building.

Further information on the Physical Design is provided in **Exhibit C, Tab 1, Schedule 1**.

Schematic diagrams of the existing and proposed facilities at the three transformer stations are provided as **Attachments 2, 3 and 4** of this Exhibit.

As indicated in **Exhibit B, Tab 3, Schedule 2,** and required by the SIA in **Exhibit F, Tab 1, Schedule 1**, to increase the east-west transfer capability to 650 MW, when the need arises, the following facilities and upgrades will be added in the future:

- Install a new +200/-100 Mvar Static Var Compensator (SVC), with its step-up transformer (to 230 kV), at Marathon TS;
- Upgrade sections of the existing 115 kV circuits A5A and T1M, which together with other circuits form a parallel path to the East West Tie lines, for a continuous summer rating of 500 A (about 100 MVA), by modifying the cross-arms and/or insulators on some of the structures of these two circuits.

Some of the facilities described are needed to meet applicable reliability standards and the IESO voltage-control requirements.

Assessment of the Rationale for the East-West Tie Expansion

Third Update Report

Submitted to the Ontario Energy Board
(EB-2011-0140)

December 15, 2015

Connecting Today.
Powering Tomorrow.

1.0 KEY FINDINGS/RECOMMENDATIONS

This update confirms the rationale for the East-West Tie ("E-W Tie") expansion project based on updated information and study results. Under the Reference assumptions, the E-W Tie expansion, which permits more effective utilization of provincial resources to meet electricity needs identified for northwestern Ontario ("the Northwest"), provides a net economic benefit of $1.1 billion compared to a local generation alternative. To test the robustness of this result against uncertainty in the assumptions, the IESO considered high and low sensitivities on a number of key parameters, of which forecast demand growth, discount rates, and capital and fixed costs for generation and transmission had the largest impacts. Based on the sensitivities tested, the net benefit of the E-W Tie project ranges from a break-even outcome associated with the Low demand forecast scenario, to $1.7 billion under high demand growth.

The E-W Tie expansion project continues to be the IESO's recommended alternative to maintain a reliable and cost effective supply of electricity to the Northwest for the long term. The IESO supports the continuation of development work in order to maintain the viability of the E-W Tie expansion project with a targeted in-service date by the end of 2020.

2.0 INTRODUCTION

The Ontario Government's Long-Term Energy Plans ("LTEP") have both anticipated the expansion of a new E-W Tie transmission line. The 2010 LTEP, published in November 2010, identified the E-W Tie as a priority transmission project,[1] and the government's subsequent 2013 LTEP, published in December 2013 focused on the unique needs of Northern Ontario and included the E-W Tie expansion project.[2] The E-W Tie expansion project is intended to increase the transfer capability into the Northwest by adding a new transmission line roughly parallel to the existing E-W Tie transmission line, which extends between Wawa and Thunder Bay.

The Minister of Energy's letter to the Ontario Energy Board ("Board") of March 29, 2011 was the impetus for the Board undertaking a designation process to select the most qualified and cost-effective transmitter to undertake development work for the E-W Tie project. Early in the proceeding (EB-2011-0140), the Board requested that the former Ontario Power Authority ("OPA")[3] provide a report documenting the preliminary assessment of the need for the E-W Tie expansion. In response, the OPA filed its original report in June 2011, titled "Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion" ("June 2011 Report").

[1] Ontario's 2010 Long-Term Energy Plan: Building Our Clean Energy Future, Figure 12, page 47.

[2] Ontario's 2013 Long-Term Energy Plan: Achieving Balance, page 52.

[3] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that combined the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator. Any assessments prior to January 1, 2015 were provided by the former OPA.

This report constitutes the Independent Electricity System Operator's ("IESO") third updated assessment of the rationale for the E-W Tie expansion project, as ordered by Board decisions Regarding Reporting by Designated Transmitter dated [September 26, 2013] and [January 22, 2015].[4] It builds upon and updates three previous E-W Tie reports prepared by the OPA: i) the original June 2011 Report; ii) the first update report, filed with the Board in October 2013, titled "Updated Assessment of the Rationale for the East-West Tie Expansion" ("October 2013 Report"); and iii) the second update report titled "Assessment of the Rationale for the East-West Tie Expansion" filed with the Board on May 5, 2014 ("May 2014 Report").

This report focuses on major changes that have occurred since the May 2014 Report and, based on these changes, provides an updated statement of the rationale for the E-W Tie expansion. This report also follows several additional filings with the Board in the E-W Tie proceeding, namely: i) the OPA's September 30, 2014 need update letter regarding the development schedule, including a recommendation and explanation of the rationale for revising the project's in-service date from 2018 to 2020; ii) the OPA's December 19, 2014 submission, titled "Context for Revised Development Schedule" filed with Upper Canada Transmission, Inc.'s ("UCT") December 19, 2014 response to the Board's October 29, 2014 letter requesting that UCT and the OPA collaborate to produce a revised development schedule for the E-W Tie based on the OPA's September 30th updated information; iii) the IESO's supporting letter of May 5, 2015 to UCT's May 15, 2015 filing with the Board provided to confirm that UCT's revised development schedule is consistent with the IESO's current information regarding the need for the E-W Tie expansion project.

In the filings referenced above, the OPA and IESO advocated that the additional time for development work afforded by the deferral of the in-service date from 2018 to 2020 be used to investigate potential cost savings for the project. To this end, UCT (o.a. NextBridge Infrastructure), the transmitter designated to develop the E-W Tie expansion project, requested that Parks Canada reconsider its decision regarding access to Pukaskwa National Park, but in June 2014 was denied that request. The IESO has also investigated the potential for cost savings from staging the project's implementation, and has refined the models and assumptions underlying this analysis, based on more detailed analysis and research.

The remainder of this report is organized as follows. Section 3 describes new activities undertaken to refine models and assumptions in preparing this update. Section 4 provides an updated conservation and demand forecast for the Northwest. It reflects changes since May 2014 and identifies major drivers for future electricity demand. Sections 5 and 6 analyze current and future internal and external resources that supply the Northwest and provide an update on Northwest capacity and energy supply needs. Section 7 provides an updated analysis of two alternatives to meet these needs: a case with no E-W Tie expansion, in which gas generation addresses the Northwest supply needs; and the E-W Tie expansion. Section 8 summarizes the IESO's recommendation.

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[4] Board Decision and Order Regarding Reporting by Designated Transmitter dated September 26, 2013, page 4, and January 22, 2015, page 5.

3.0 ACTIVITIES UNDERTAKEN IN PREPARING THIS UPDATE

In the year since the OPA issued its letter deferring the E-W Tie expansion, the IESO has undertaken a variety of activities to investigate potential areas for cost savings, update system capability and Northwest operational needs, and refine and update the models and assumptions used in this assessment. These activities are introduced here, to provide context for the updated results and information presented in subsequent sections of this report.

Updated Transmission Cost Estimates

For this update, the IESO asked the respective transmitters to review the capital cost estimates for the new line and the station upgrades. Based on the most recent information, and accounting for Parks Canada's decision not to allow a route through Pukaskwa National Park, the previous planning estimate of $500 million for the line was confirmed by NextBridge Infrastructure.

For the station costs, Hydro One provided a revised estimate of approximately $150 million for the 650 MW E-W Tie expansion, up from the previous planning estimate of $100 million, reflecting more detailed design work than was previously available. This estimate accounts only for costs directly attributable to the E-W Tie project. Costs associated with a portion of the station upgrade work that would be required to enable the existing system to meet new NERC standards while maintaining system capability and operational requirements, regardless of whether the E-W Tie expansion goes ahead, was deducted from the station cost estimates.

Staging of Station Facilities

The IESO has identified a potential opportunity to defer costs by staging the installation of station facilities, while still maintaining reliability. This would involve an interim stage consisting of "twinning" the circuits, creating two "super-circuits", one carried by the existing E-W Tie line structures and the other on the new line. This interim stage would provide a westbound transfer capability of approximately 450 MW.

The interim stage would allow for approximately $100 million of the station facility costs to be deferred.

Refined Transmission System Limits

The IESO has continued to refine its studies of transmission system limits and interface capabilities, reflecting the most up-to-date available supply and demand information and application of new reliability criteria. These updated limits are reflected in updates to the capacity and energy models underlying the E-W Tie analysis.

Previously, the reported westbound capability of the existing E-W Tie was based on voltage and transient stability limitations. In this update, the westbound capability of the existing E-W Tie has been revised downward based on further study to assess thermal limitations on the existing system (see section 5.2). This means that the incremental capacity provided by the E-W Tie expansion is greater. It also has the effect of increasing the generation capacity requirements in the generation alternative, all else being equal, compared to the higher existing E-W Tie limit used in the May 2014 Report.

The transfer capabilities of transmission interfaces outside the Northwest have also been refined in this update. The eastbound limit on the interface between Wawa and Sudbury, and the southbound limit between Sudbury and southern Ontario, have both been modeled to more accurately reflect their current capabilities to export power under system peak conditions. In the generation alternative, this has the effect of reducing the effectiveness of Northwest generation in providing capacity to the rest of the province.

Refined Resource Assumptions

The IESO continually updates its assumptions and models by observing market trends and conducting research. Since the May 2014 Report was published, the IESO has updated its assumptions for natural gas-fired generation, with a particular emphasis on generation sited in the Northwest, through third party consultants, external resources, and past procurement experience.

New learning suggests that to provide reliable peak capacity in the Northwest, storing reserve fuel on-site, at a relatively small capital and operating cost increase, is more cost-effective than procuring "firm" Gas Delivery and Management ("GD&M") services. Due to pipeline infrastructure, limited natural gas storage capacity in northern Ontario, and a mismatch in the commitment timeframes for gas and electricity, procuring "firm" service in the Northwest is expected to be more costly than the same level of GD&M service in southern Ontario. Having fuel on-site would allow a developer to procure "interruptible" GD&M services for natural gas as the primary fuel, but with a backup fuel supply in case service is interrupted. The onsite fuel could feasibly be diesel fuel oil, liquefied natural gas or compressed natural gas. Based on discussions with natural gas distribution companies about historical gas demand interruptions in the Northwest, the on-site fuel is expected to rarely be called upon.

In this update, the cost and technology assumptions for new-build natural gas-fired generation installed in the Northwest—i.e., the alternative to the E-W Tie assessed in this report—are based on this on-site reserve fuel strategy.

4.0 NORTHWEST CONSERVATION AND DEMAND

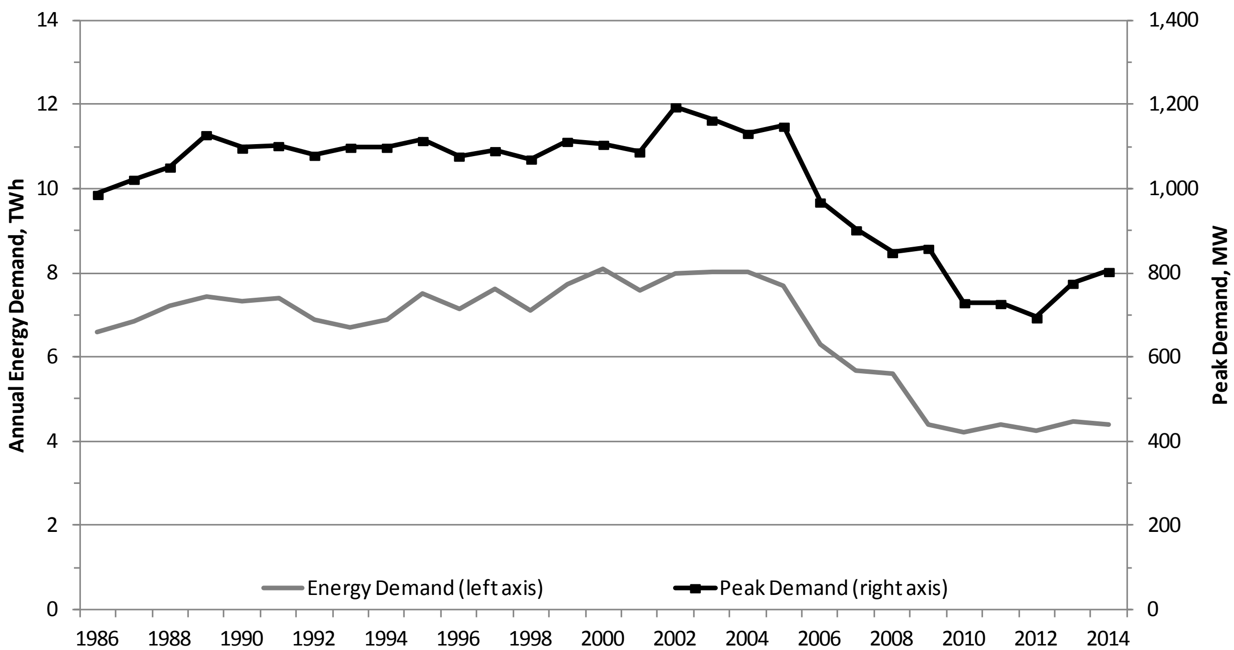
Throughout the planning and development of the E-W Tie expansion project, the IESO has maintained regular discussion with stakeholders and customers in the Northwest and continues to monitor developments that may affect electrical demand in the region. The forecast in this report reflects updated information and provides a range of demand scenarios based on the inherent uncertainty of industrial development in the region. As noted in the previous two need update reports, Northwest electrical demand is dominated by large, industrial customers and can fluctuate significantly in response to changing economic and market conditions. The Northwest is a winter-peaking region, in contrast to southern Ontario where electricity demand usually peaks during the summer months.

In this update, the demand forecast has increased marginally in magnitude, with growth occurring slightly later than in the May 2014 forecast, based on updated information of various developments.

4.1 Historical Northwest Demand

Historical electricity demand in the Northwest is presented in Figure 1 below. This update includes actual energy and demand data from 2014, which was not available when the May 2014 Report was prepared. The winter of 2014 saw an increase in demand in the Northwest driven by extreme temperatures and modest growth in the industrial sector. The Northwest electricity system performed well under the higher demand conditions of 2014, which included a winter peak of approximately 800 MW, and annual energy demand of almost 4.5 TWh.

Figure 1. Historical Northwest Electricity Demand



4.2 Drivers of Northwest Demand

The IESO continues to work together with interested parties to understand the drivers for demand in the Northwest, including engaging with stakeholders such as Common Voice Northwest, mining companies and industry associations, and carrying out discussions with the Ontario Ministry of Northern Development and Mines. The updated forecast reflects changes in the outlook for industry, as well as other developments in the Northwest.

In comparison to the May 2014 Report, drivers of Northwest demand that have changed include: more certainty in the development of several mining projects; updated information on the electricity requirements and timing associated with the TransCanada PipeLines Limited ("TCPL") proposed "Energy East" project; and consideration of recent plant closures in the pulp and paper sector.

Mining Sector

The IESO has continued to engage mining companies with developments in Ontario and review technical documents to understand the feasibility, timing and likelihood of various developments. Factors such as commodity prices, access to capital and environmental considerations act as indicators of potential growth in the sector. Several mining projects in the Fort Frances and Red Lake areas have advanced to construction or initial production phases and various other projects throughout the region have had success raising capital and advancing their feasibility and environmental assessments. On the other hand, several other projects have experienced set-backs due to factors such as low commodity prices and environmental hurdles. The demand forecast considers the latest available information on the location, size and stage of development of mining projects in the Northwest.

Pulp and Paper Sector

Ontario's pulp and paper sector has been in decline for over 10 years. This decline continued in 2014 with the closure of two Ontario plants, one in the Northeast and one in the Northwest. There is a potential for demand stabilization from the retrofitting of old pulp and paper facilities to produce other fibers such as Rayon, however a substantial recovery of the pulp and paper sector is considered unlikely.

TransCanada Energy East Pipeline

This updated forecast includes updated information on the electrical requirements of the Energy East pipeline project. Two demand forecasts were considered for this project—medium and high—reflecting the impacts on Northwest demand of two alternate connection options proposed by TCPL.

Other Forecast Components

Minimal or no change has been made for the remaining components of the Northwest demand forecast since the May 2014 Report:

- Forestry sector
- Connection of remote communities remains on track for 2020
- Natural growth in residential, commercial and other industrial sectors

The IESO remains engaged in working with local distribution companies ("LDC") to implement the Conservation First framework, consistent with the 2013 LTEP and the March 31, 2014 Conservation First Directive from the Ministry of Energy to the OPA. LDC progress towards meeting the conservation targets will continue to be tracked through Conservation and Demand Management ("CDM") Plans and evaluation, measurement and verification ("EM&V") activities, and the conservation assumptions for the Northwest will continue to be updated accordingly.

4.3 Northwest Demand Scenarios

An updated demand forecast for the Northwest was developed, taking into account the impacts of the various drivers described above. Consistent with the previous two update reports developed by the

OPA, the IESO has represented demand growth uncertainty in the region by developing three scenarios to explore the robustness and flexibility of transmission and supply options under a range of outcomes. Key aspects of the scenarios are as follows:

- **Reference Scenario.** In this scenario, mining sector demand considers proposed mines that have passed significant development milestones. Mining loads are assumed to persist for the expected lifetime of the proposed developments. This scenario assumes modest growth in the forestry sector in the short and medium term and does not assume recovery of the pulp and paper sector. This scenario assumes the Energy East pipeline will proceed to production in 2020 under the medium demand forecast for this project.
- **High Scenario.** This scenario considers the impact of stronger and faster development in the mining sector which could potentially be driven by factors such as increased commodity prices. This scenario also reflects the stabilization of the pulp and paper sector and assumes the high demand forecast for the Energy East pipeline conversion project.
- **Low Scenario.** This scenario describes a more restrained outlook in the mining sector, continuing decline in the pulp and paper sector, and it assumes that the Energy East pipeline conversion project does not proceed.

The demand assumptions for Remote Communities, residential, commercial and other industries (other than those mentioned above) are the same in each scenario.

The resulting Northwest peak and annual energy demand scenarios, net of savings from planned conservation, are shown in Figure 2 and Figure 3. The Reference demand scenario shows the Northwest forecast increasing quickly in the medium term, due to advancing mining developments which are expected to come online, followed by more gradual growth in the long term. The wide range between the High and Low scenarios reflects the uncertainty in the assumptions underlying the forecast.

For comparison, the Reference scenario prepared for the May 2014 Report is also included in Figures 2 and 3. The current Reference forecast has a slower near-term growth rate than the May 2014 Reference forecast but is higher than the May 2014 Reference forecast in the long term.

Figure 2. Northwest Net Peak Demand Forecast Scenarios

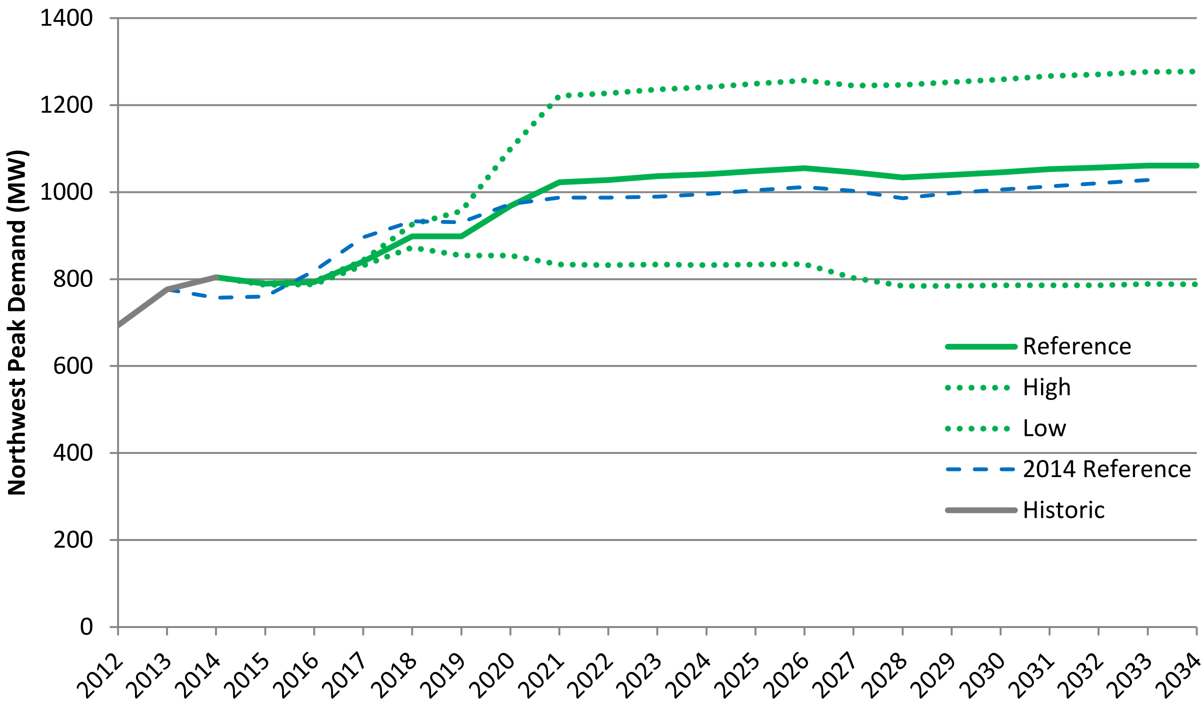
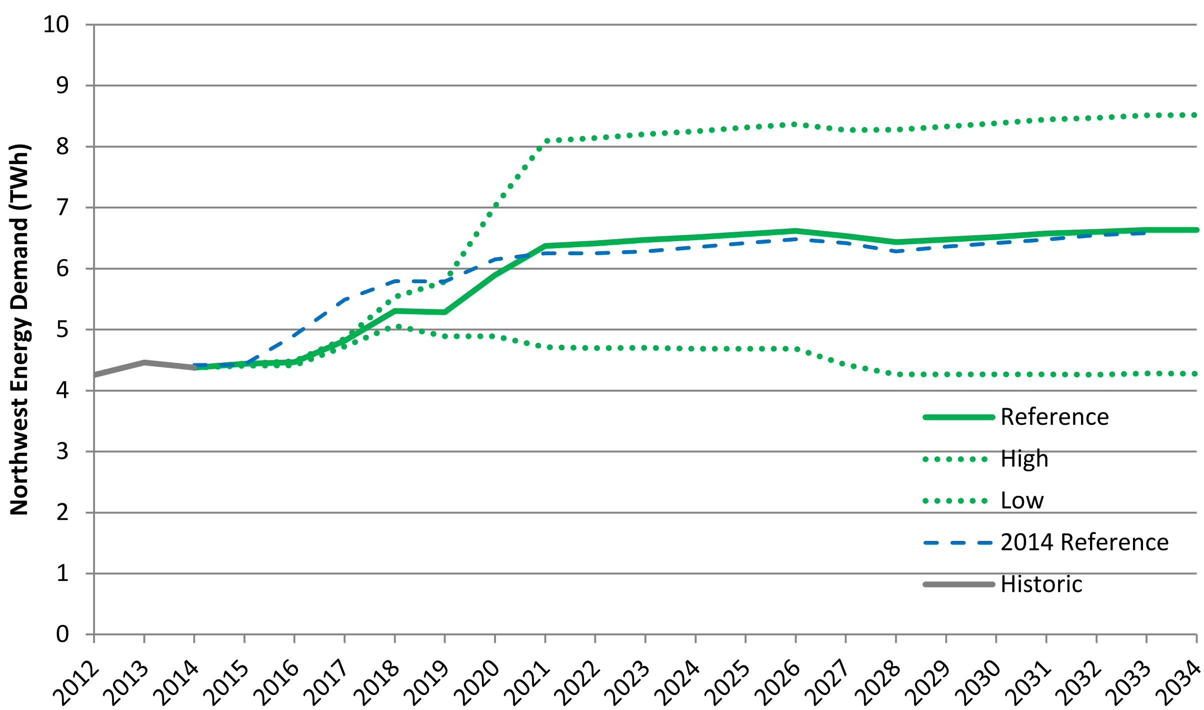


Figure 3. Northwest Net Energy Demand Forecast Scenarios



5.0 EXISTING RESOURCES TO SUPPLY NORTHWEST DEMAND

The Northwest relies upon both internal resources (generation located in the Northwest) and external resources (generation outside the Northwest accessed through existing ties) to meet its electricity supply and reliability requirements. An update on the Northwest supply outlook since the May 2014 Report is provided below.

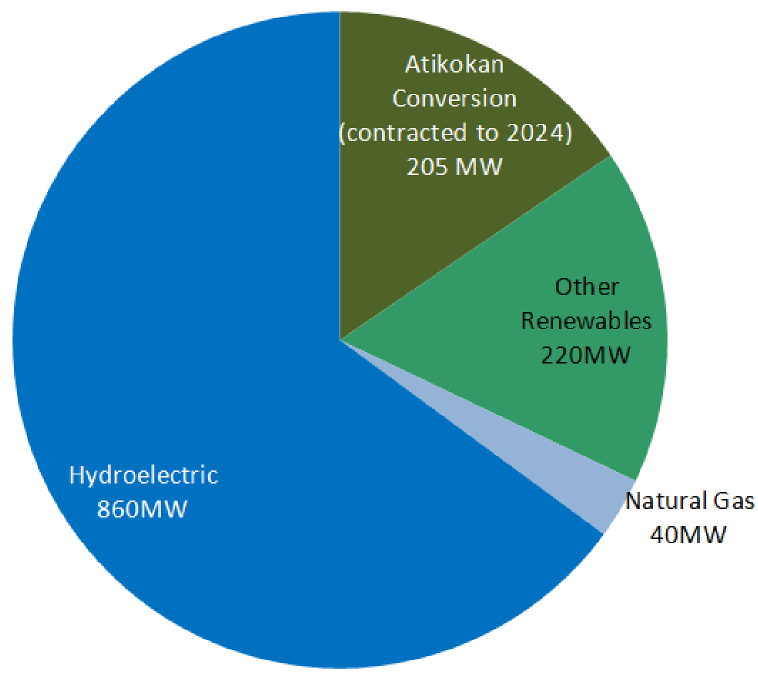
5.1 Internal Resources in the Northwest

The IESO has updated its assumptions regarding supply resources in the Northwest, where new information is available. The following changes have been made since the May 2014 Report:

- The 60 MW generator at Fort Frances, previously considered as embedded generation, has been removed from service as the operation has shut down.
- The rated capacities of the Atikokan Biomass Generating Station and the Thunder Bay Advanced Biomass Generating Station have been adjusted upward slightly based on updated contract and performance data.
- The maximum contracted hydroelectric capacity over the planning period has increased from 835 MW to 861 MW, due to projects that received contracts in the first phase of the Feed-in Tariff ("FIT") program coming into service.
- The capacity contribution (expected available capacity during peak hours) of hydroelectric generation has been updated based on new data and ongoing model improvements. The May 2014 Report assumed a winter capacity contribution of around 32% during low water years; in this report, the winter capacity contribution during low water years has been increased to 45%.
- The expiration of wind and solar generation contracts has been accounted for in this update.
- Some small-scale distribution-connected solar and gas plants that began operation prior to 2014 are now included in the demand forecast as embedded loads; these resources have been removed from the supply side model.
- 40 MW of new hydroelectric and solar capacity contracted primarily through the FIT program have come into service since the previous analysis was completed.

The updated installed capacity of Northwest internal resources in the year 2020 is 1,325 MW and is shown by fuel type in Figure 4.

Figure 4. Northwest Internal Resources by Type in 2020 (Installed Capacity)



5.2 External Resources Supplying the Northwest

Additional supply is provided to the Northwest through the existing E-W Tie; a 230 kV double-circuit transmission line that extends between Wawa TS and Lakehead TS, linking the Northwest system to the rest of Ontario.

In the May 2014 Report, the westbound transfer capability of the E-W Tie was quoted as 240 MW. This represents the operational limit for transfers across the E-W Tie that will ensure that both transient and voltage stability will be maintained following a double-circuit contingency (fault) involving the E-W Tie.

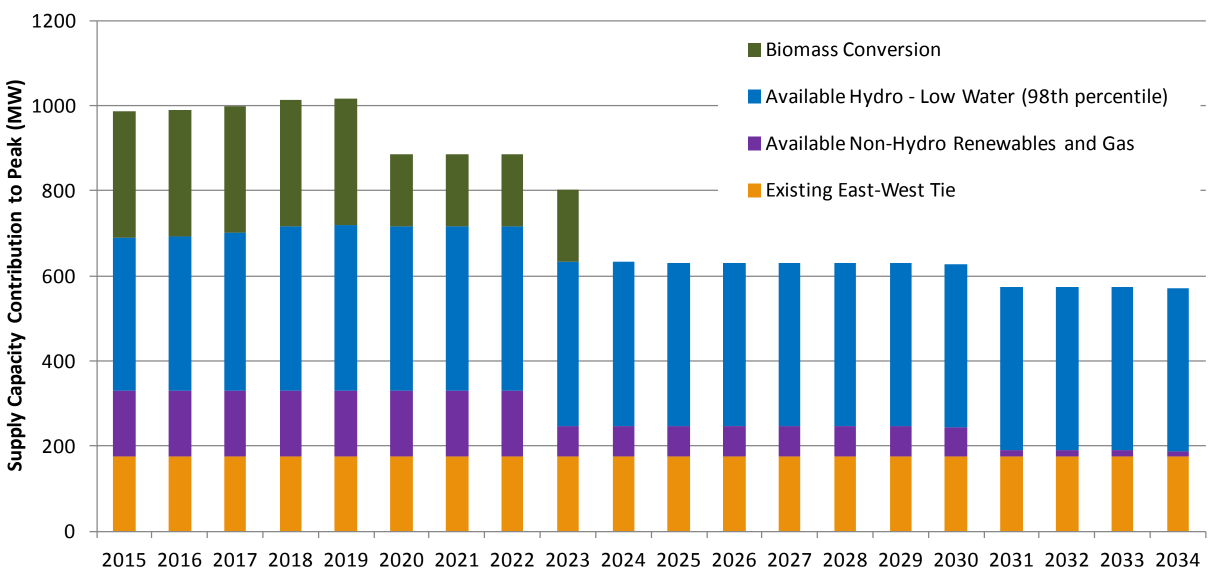
It has subsequently been recognized that following the loss of the double-circuit line between Marathon TS and Lakehead TS, the thermal rating of the parallel 115 kV single-circuit line can be more limiting under certain ambient conditions. Based on the ambient temperatures specified in the Ontario Resource and Transmission Assessment Criteria ("ORTAC") that are to be used in planning studies, the maximum transfer that can occur across the E-W Tie will be limited to 175 MW during the winter period and 155 MW during the summer by the thermal rating of this 115 kV line. Since these latter values are more restrictive, they have been used in the analysis underlying this report.

5.3 Summary of Existing Resources

The existing internal and external resources assumed to be available to supply the Northwest in this planning analysis are shown in Figure 5. The figure reflects the available capacity of internal resources at the time of Northwest peak demand under low water conditions. It also includes the westbound capability of the existing E-W Tie.

As Figure 5 indicates, available peak supply capacity is expected to be reduced at two points in the planning horizon: in 2020, corresponding to the expiry of the contract for Thunder Bay Advanced Biomass Generating Station; and in 2024, when the contract for Atikokan biomass operation expires.

Figure 5. Northwest Peak Supply Capacity under Low Water Conditions



6.0 THE NEED FOR ADDITIONAL SUPPLY FOR THE NORTHWEST

As described in previous reports, the forecast supply needs for the Northwest consist of both capacity and energy components. Based on the current outlook for Northwest demand and supply, and incorporating refined assumptions and models described in section 3, the IESO updated the assessment of the reliability and adequacy of the Northwest system. The updated capacity and energy requirements are described below.

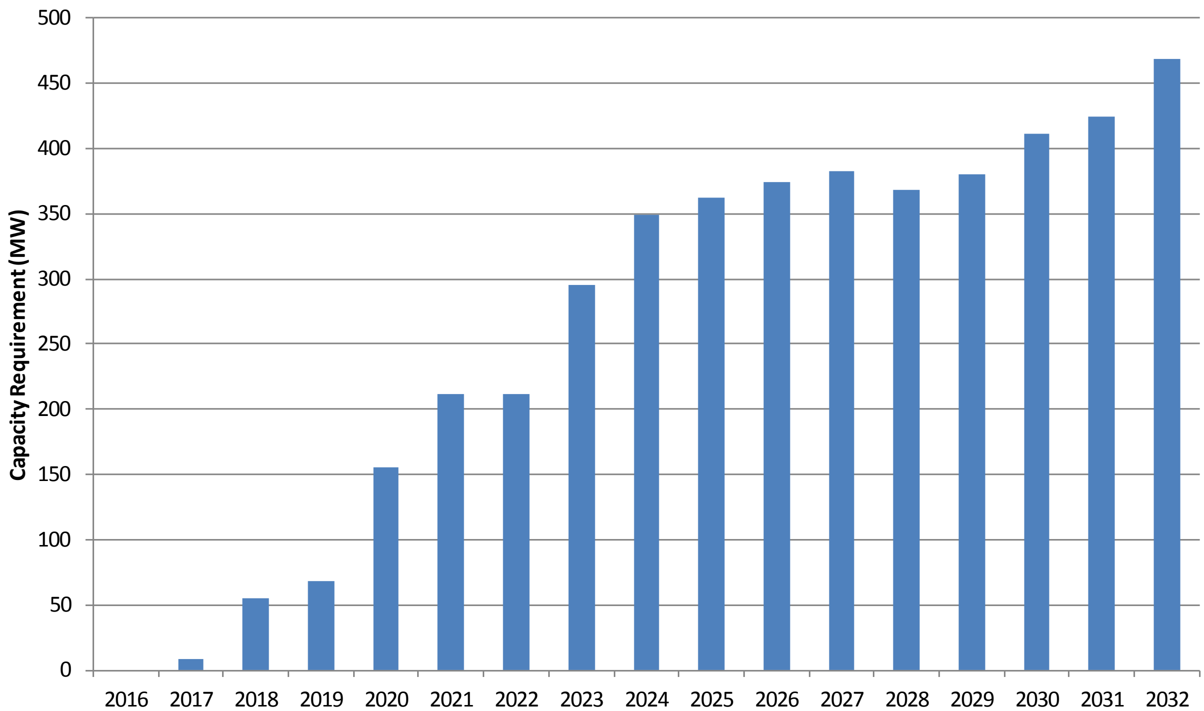
6.1 Expected Capacity Requirement

Consistent with the May 2014 Report, the IESO conducted a reliability assessment using a probabilistic approach to determine capacity requirements in the Northwest. As water conditions have a strong impact on overall supply availability in the Northwest, the probabilistic approach utilizes a range of water conditions.

The updated capacity need, based on the Reference peak demand scenario with no E-W Tie expansion, is shown in Figure 6. The capacity need increases from approximately 150 MW in 2020 to around 350 MW with the expiry of the Nipigon NUG and the Atikokan biomass contracts in 2023 and 2024 respectively. The need for additional capacity continues to climb gradually through the remainder of the planning period due to further load growth and the expiry of some smaller supply contracts, approaching 500 MW in the early 2030s.

As noted in the May 2014 Report, there is a small projected capacity need in the interim years before the E-W Tie expansion, based on assessment of planning criteria.[5] This need is lower than in the May 2014 Report due to the updated demand forecast as well as updated data and assumptions about hydroelectric availability during peak periods, and is associated with low-water years only. The IESO will continue to monitor this need and, if necessary, deploy short-term options to bridge the gap until the E-W Tie expansion comes into service.

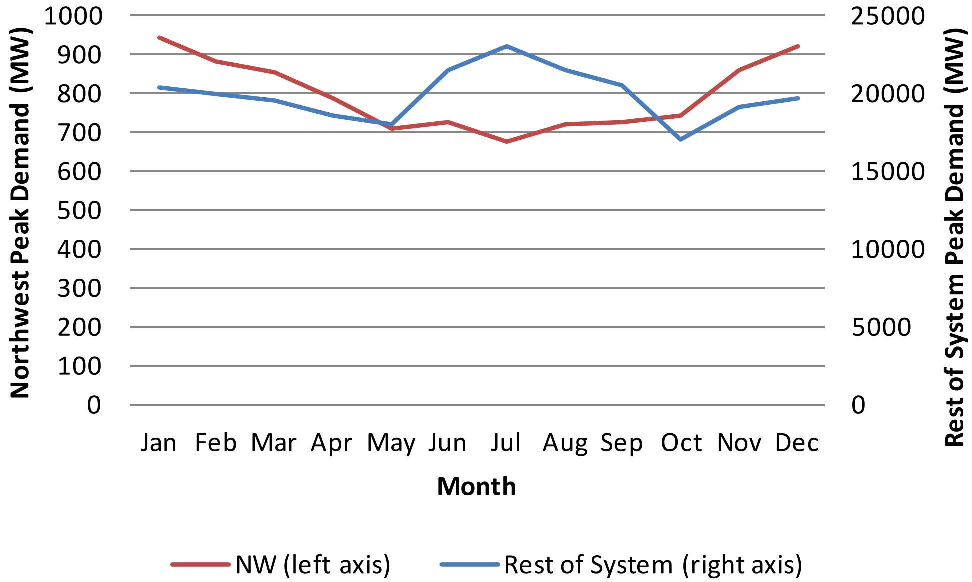
Figure 6. Expected Incremental Northwest Capacity Requirement under Reference Demand



As demand in the Northwest is winter-peaking, the incremental capacity requirements in the Northwest are greatest during the winter months. This is in contrast to southern Ontario, where peak demand requirements are highest during the summer months. This is demonstrated in Figure 7, using 2020 as an example year. This offset in capacity requirements enables the sharing of resources for capacity adequacy and increased system efficiency for energy arbitrage with the E-W Tie expansion.

[5] Assessment of the Northwest system based on operating criteria indicates that there is no capacity need prior to 2020.

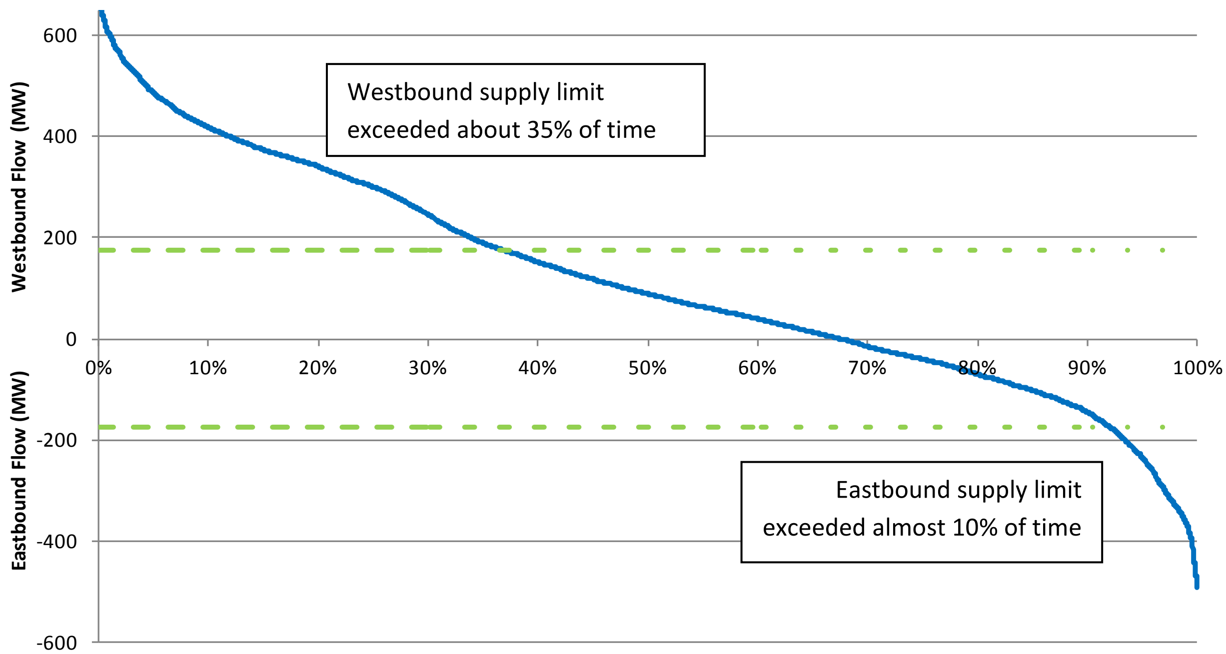
Figure 7. Timing of Demand in the Northwest vs. Rest of Ontario in 2020



6.2 Expected Energy Requirement

The expected energy requirement in the Northwest is defined by the energy demand forecast, as well as the supply capabilities of local generation and the existing E-W Tie. Figure 8 provides an updated forecast E-W Tie flow duration curve, for all hours of the year 2021, based on the latest Reference demand forecast and median water conditions. In this update, expected westbound flows exceed the existing E-W Tie capability approximately 35% of the time. This is based on application of the winter rating of 175 MW throughout the year. Applying the more restrictive limit of 155 MW during the summer months would likely result in a higher level of westbound congestion. Going eastbound, congestion is expected to occur just under 10% of time in 2021. The energy requirement is expected to grow with the demand forecast over the planning horizon.

Figure 8. Unconstrained Flow and Planning Limits on the Existing E-W Tie for the Year 2021



7.0 ANALYSIS OF ALTERNATIVES TO MEET NORTHWEST SUPPLY NEEDS

As in previous reports, two alternatives to meet the Northwest capacity and energy needs were evaluated based on the capacity needs identified for each of the demand scenarios: Reference, Low and High. The alternatives are broadly defined as follows:

(1) **No E-W Tie expansion.** In this alternative, all of the forecast capacity and energy needs are met through the addition of new gas-fired simple cycle gas turbine ("SCGT") generation in the Northwest, with the size of units and the timing of installation defined to meet the needs as they arise during the planning period. Under the Reference demand forecast, a total of 500 MW of generation is included.

(2) **E-W Tie expansion.** In this alternative, the E-W Tie expansion project provides a foundation for meeting the Northwest needs, with additional generation installed to meet any incremental supply requirements. In this update, a staged implementation of the E-W Tie expansion was adopted, with the interim 450 MW E-W Tie stage and the final 650 MW stage installed as required to meet the capacity needs throughout the study period. For the High growth forecast, a need for additional supply beyond the capability of the expanded E-W Tie emerges in the later years of the forecast; this supply is included in the analysis.

In both alternatives, local generation is assumed to consist of new-build natural gas-fired generation, utilizing on-site reserve fuel. For the reasons discussed in the May 2014 Report, continuing to operate the Atikokan and Thunder Bay conversions beyond their contemplated expiry dates was not assumed in the alternative analysis.

Another alternative that was not analyzed in this (or previous) updates is a potential firm import purchase from Manitoba. The existing intertie between Ontario and Manitoba has a capacity of about 300 MW. Currently, it is used for short-term economic trades between the two jurisdictions and there are no contractual obligations to provide firm capacity in effect. For imports to be a viable alternative, the Northwest system would need to be able to absorb the required capacity beyond the border and transfer it within the Northwest to where it is needed. Currently, without major system expansion, only about 150-200 MW can be accommodated before running into constraints on the transmission system between Kenora and Dryden. Moreover, utilizing the existing intertie for firm import purchases would reduce its availability for economic transactions that currently can assist in meeting operational needs.

7.1 Cost-Effectiveness Comparison of Generation and Transmission Alternatives

Consistent with previous E-W Tie expansion need update reports, an economic analysis of the two alternatives was conducted and their relative net-present-value (“NPV”) was compared. A sensitivity analysis was performed to test the robustness of the results under a variety of conditions. Among the sensitivities tested were the Reference, Low and High demand forecast scenarios, ranges in the cost of the generation alternative, and various other factors.

In addition to reflecting the updated capacity and energy needs, the economic analysis includes the refined assumptions identified in section 3.

Changes in assumptions since the May 2014 Report are as follows:

- The Reference demand forecast was updated as per the changes identified in section 4.3. Sensitivities to test the impacts of the updated Low and High demand growth scenarios on the NPV were performed.
- The updated existing supply resources described in section 5, including the updated westbound ratings for the existing E-W Tie, are reflected in the analysis.
- Eastbound constraints on the transmission interfaces between Wawa and Sudbury, and between Sudbury and southern Ontario, were included in the energy and capacity models based on refined studies of the capabilities of these interfaces.
- Additional study has identified that due to diversity in the demand profiles of the Northwest and the rest of Ontario (see section 6.1), fewer provincial resources are required to supply the Northwest in the E-W Tie expansion alternative.
- The transmission costs for the E-W Tie expansion are assumed to be $500 million for the line and $150 million for the stations (see section 3). A portion of the station costs is deferred consistent with the staged expansion of the E-W Tie included in this update.

- A better understanding of needs internal to the Northwest has influenced the SCGT technology type, sizing, and location, resulting in a net increase in capital costs for the “No E-W Tie expansion” alternative. A sensitivity of +/- 25% was assessed on the capital and ongoing fixed costs for generation.
- The study period extends from 2021, the first full year that the E-W Tie expansion would be in service, to 2050, when the first replacement decision is expected; this decision is associated with the generation alternative.
- Natural gas prices were assumed to be an average of $4.50/MMBtu throughout the study period. A sensitivity was performed with average gas prices of $8.50/MMBtu.
- The assessment is performed from a ratepayer perspective, and now includes all costs incurred by developers, which are passed on to ratepayers.[6]

The following assumptions remain unchanged from the May 2014 Report:

- The NPV of the cash flows is expressed in 2015$ CDN.
- The NPV analysis was conducted using a 4% real social discount rate. Sensitivities at 2% and 8% were performed.
- Median-water hydroelectric energy output was used for energy simulation in the economic analysis.
- The life of the station upgrades was assumed to be 45 years; the life of the line was assumed to be 70 years; and the life of the generation assets was assumed to be 30 years.
- New capacity in the Northwest and the rest of Ontario was added, as required, to satisfy reliability criteria. These capacity needs were determined as described in section 6.1. A sensitivity to determine the impact of adding 100 MW of gas-fired generation in the Northwest was performed.

Under the Reference assumptions, the E-W Tie expansion provides a net economic benefit of $1.1 billion compared to the no-expansion alternative. To test the robustness of this result against uncertainty in the assumptions, the IESO considered high and low sensitivities on a number of key parameters, of which forecast demand growth, discount rates, and capital and fixed costs for generation and transmission had the largest impacts. Based on the sensitivities tested, the net benefit of the E-W Tie project ranges from a break-even outcome associated with the Low demand forecast scenario, to $1.7 billion under high demand growth.

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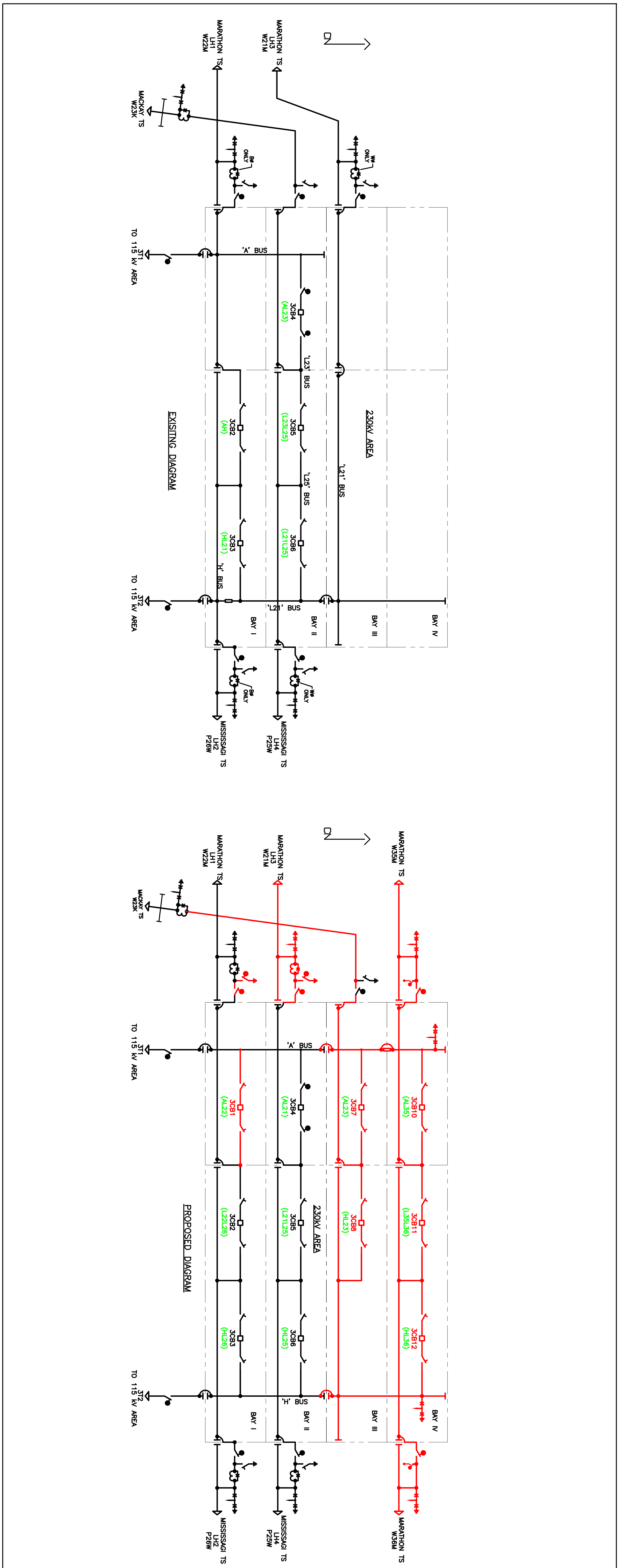
[6] The previous analyses were completed from a societal perspective. Taxes and returns assumed to change hands within Ontario were therefore not included in the economic analysis.

The E-W Tie expansion would provide additional benefits, beyond meeting the reliability requirements of the Northwest: system flexibility, removal of a barrier to resource development, reduced congestion payments, reduced losses, and improved operational flexibility. These benefits are additive to the economic benefits and form an important part of the rationale for the project.

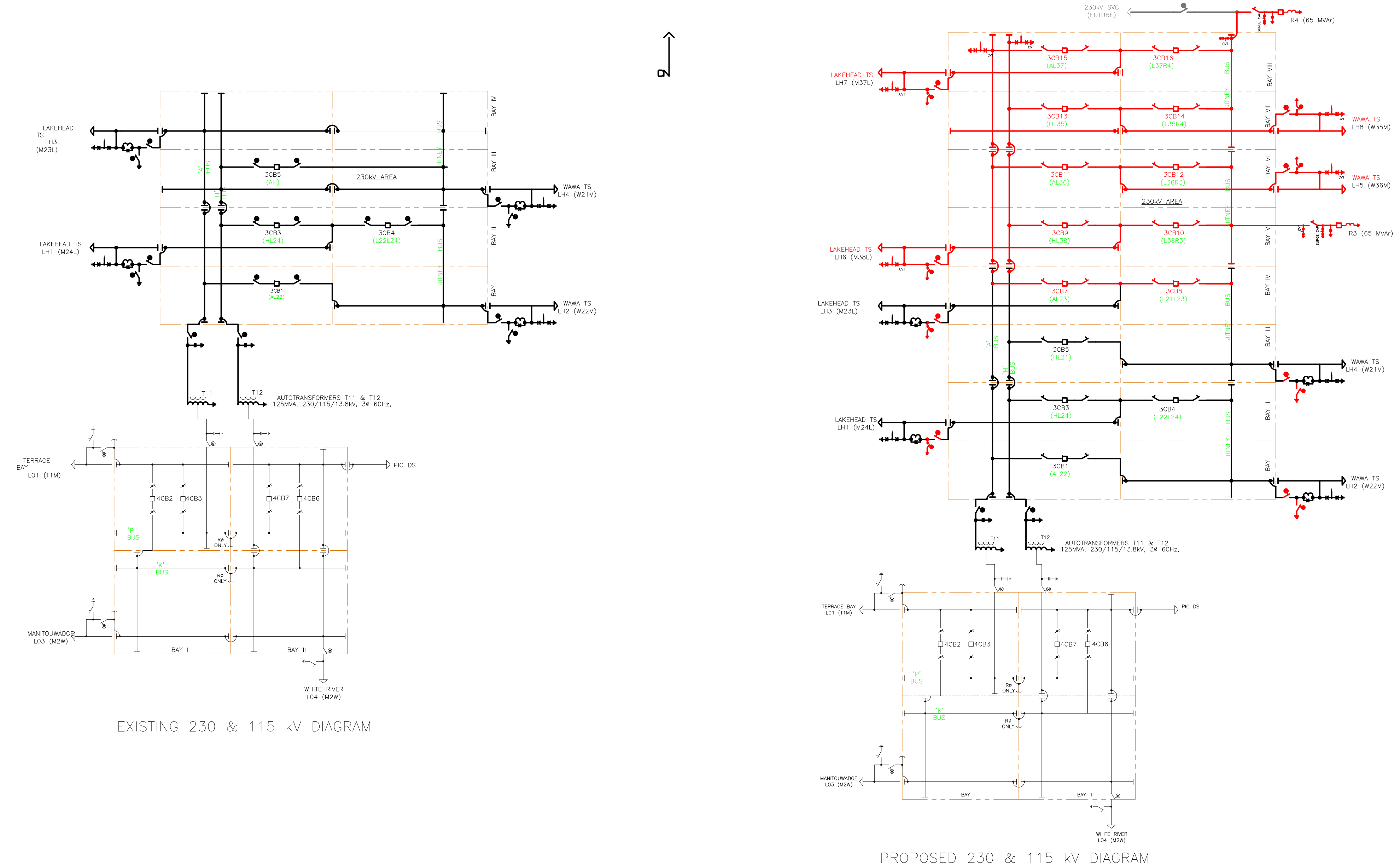
8.0 CONCLUSION AND RECOMMENDATION

The IESO's most recent analysis illustrates that the E-W Tie expansion is economic under a wide variety of conditions. On this basis, the IESO continues to recommend the E-W Tie expansion as the preferred alternative to maintain a reliable and cost-effective supply of electricity to the Northwest for the long term.

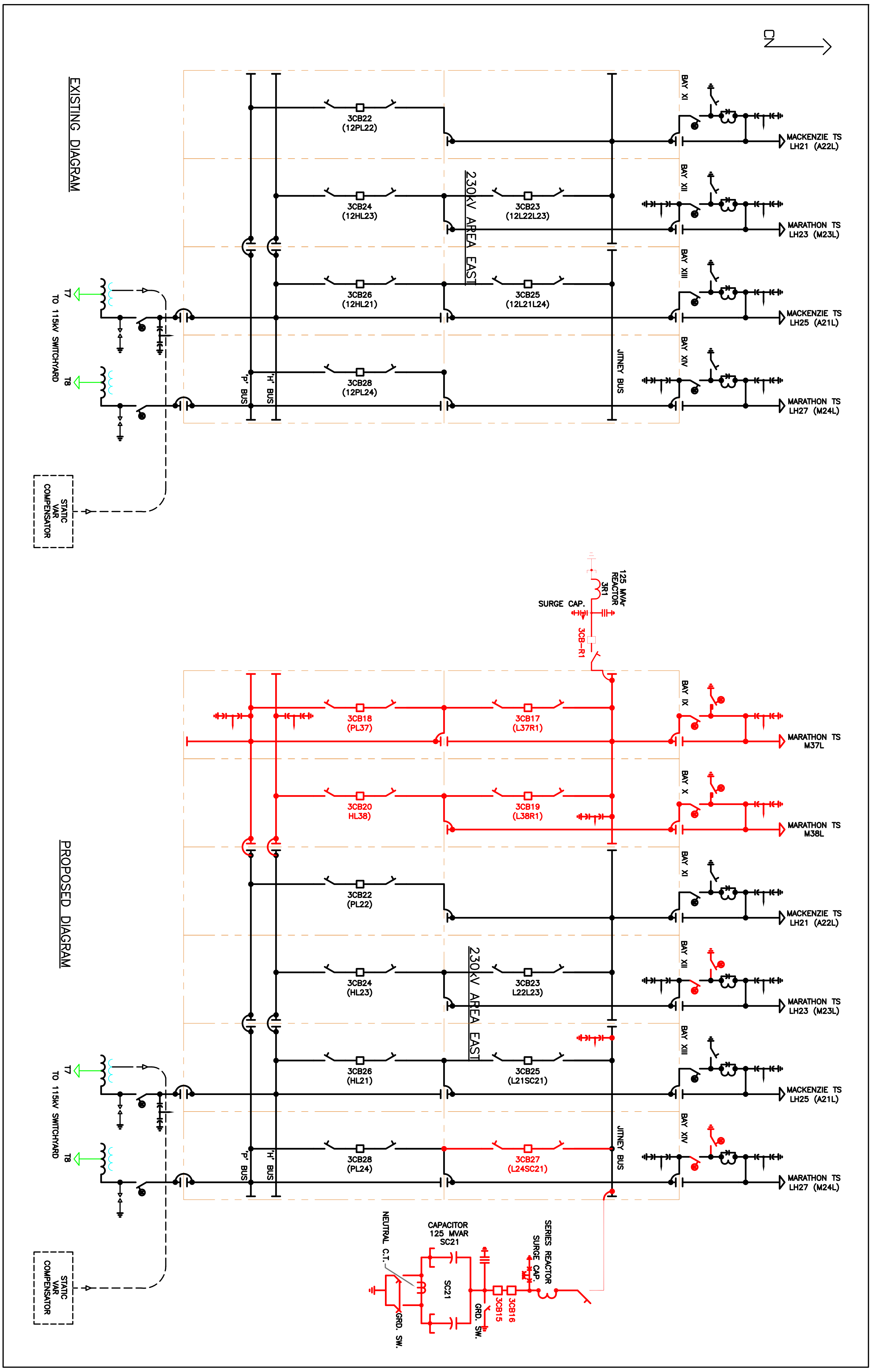
Based on the updated demand forecast, the timing of the needs is consistent with the 2020 in-service date recommended in the OPA's 2014 letter. Therefore, the IESO continues to recommend that project development proceed toward a targeted 2020 in-service date, and to support the continuation of development work to ensure the continued viability of the project.



Wawa TS - Existing and Proposed Development Diagram of 230kV Switchyard
Additions in Red



Marathon TS - Existing & Proposed Development Diagram of 230kV Switchyard Additions in Red



Lakehead TS - Existing & Proposed Development Diagram of 230kV Switchyard East
Additions in RED

Evidence In Support of Need

In March 2016 an "Order in Council" was issued by the Ministry of Energy to the Ontario Energy Board declaring that the East-West Tie Project is needed as a priority project and requesting an in-service date of 2020[1]. In order to in-service the EWT Line, Hydro One must undertake upgrades to its stations facilities.

The IESO's evidence, filed as Exhibit B, Tab 3, Schedule 2, confirms that additional or upgraded station facilities are required at the three terminal stations. This will enable the EWT Project to provide the targeted power transfer capability as recommended in the IESO Third Update Report submitted to the Board on December 15, 2015 (see Exhibit B, Tab 2, Schedule 1, Attachment 1) while meeting the requirements of the TPL-0014 standard of NERC and the ORTAC assessment criteria of the IESO.

Hydro One agrees with the IESO's evidence.

[1] Exhibit B, Tab 1, Schedule 1, Attachment 1.

Independent Electricity System Operator

East-West Tie Project Evidence

May 29, 2017

Connecting Today. Powering Tomorrow.

Table of Contents

1.0 Project Background

The proposed East-West Tie Project (the "EWT Project" or "Project") is comprised of: (i) a new, double-circuit, 230 kV, overhead transmission line that will connect Wawa TS in the Northeast and Lakehead TS in the Thunder Bay area in the Northwest (the "new EWT Line" or "new EWT Line Project") and (ii) all associated station facilities at Wawa TS, Marathon TS and Lakehead TS (the "EWT Station" or "EWT Station Project").[1]

On November 23, 2010 the Ontario government published the Long-Term Energy Plan – *Building Our Clean Energy Future*[2] (the "2010 LTEP"). The 2010 LTEP identified the EWT Project as one of five priority transmission projects, based on advice provided by the former Ontario Power Authority ("OPA") – now the Independent Electricity System Operator ("IESO") and hereinafter referred to as the IESO. The 2010 LTEP recommended that the Ontario Energy Board (the "Board") undertake a designation process to select the most qualified and cost effective transmission company to develop the Project. On March 29, 2011, the former Ontario Minister of Energy, Brad Duguid, issued a letter to the Board to this effect.[3]

1.1 Designation Process

Subsequently, at the Board's request, the IESO published on June 30, 2011 the "Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion". The report recommended the expansion of the East-West Tie as the preferred alternative to meet the long-term electricity needs of Northwestern Ontario. The IESO's project definition (double circuit, 230 kV, overhead transmission line) was subsequently adopted by the Board as the reference option for the Board's East-West Tie designation process, as specified in Appendix A[4] of the "Minimum Technical Requirements for the Reference Option of the East-West Tie Line".[5] This document, which was published November 9, 2011, as an attachment to the Board's letter to registered electricity transmitters for the new EWT Line

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[1] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/291892/view/OPA%20_Report_EWT_2011-06-30.PDF

[2] http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf

[3] https://www.oeb.ca/oeb/_Documents/Documents/Ministers_Letter_20110329.pdf

[4] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/315698/view/Appendix%20A_E-W%20Tie%20Line_Minimum%20Design%20Criteria%20for%20the%20Reference%20Option_20111220.PDF

[5] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/322963/view/Letter_E-W%20Tie%20line%20letter%20to%20registered%20transmitters-20120202.PDF

Project, specified the general concepts to be used in the design and costing of the reference option of the EWT Project.

On February 2, 2012 the Board published notice that it was initiating a proceeding to designate an electricity transmitter to undertake the development work for the new EWT Line. On August 7, 2013, the Board published its Phase 2 Decision and Order for the designation proceeding, designating Upper Canada Transmission, Inc. operating as NextBridge Infrastructure ("NextBridge") as the proponent to develop the line.[6]

1.2 IESO Need Updates

The Board's Phase 2 Decision and Order also required the IESO to file a schedule for the preparation and filing of need updates. In accordance with its original filed schedule, the IESO provided updates to the Board on the need and rationale for the EWT Project on October 8, 2013[7] and May 5, 2014.[8]

On September 30, 2014 the IESO wrote a letter[9] to the Board recommending the extension of the in-service date of the EWT Project from 2018 to 2020 due to the slower pace of mining and other infrastructure development in the Northwest. The letter also highlighted the benefits of extending development work and potential costs savings, including considering staging the implementation of the station facilities and exploring a shorter line route through Pukaskwa National Park.[10]

Following the deferral of the in-service date, NextBridge provided a revised schedule for need updates to the Board supported by the IESO.

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[6] http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2011-0140/Dec_Order_Phase2_East-WestTie_20130807.pdf

[7] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/412719/view/OPA_NeedUpdateReport_20131008.PDF

[8] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/437045/view/OPA_UpdateReport_EWT_20140505.PDF

[9] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/451101/view/OPA%20-%20EWT%20Development%20Schedule%202014%2009%2030.PDF

[10] In an update to the Board on June 24, 2015 NextBridge confirmed that Parks Canada would not grant them access to study the route through Pukaskwa National Park.

On December 15, 2015, the IESO filed a third need update report in accordance with the revised schedule.[11] This third (and most recent) update report on the assessment of the rationale for the EWT Project, made the following conclusions and recommendations:

1. The rationale for the Project is confirmed based on updated information and study results.

2. The Project is projected to provide a net economic benefit of $1.1 billion compared to a local generation alternative, under the reference assumptions used in the studies. Consideration of high and low sensitivities on a number of key parameters produced a net benefit for the EWT Project ranging from a break-even outcome to $1.7 billion.

3. The Project continues to be the IESO's recommended alternative to maintain a reliable and cost effective supply of electricity to the Northwest over the long term.

4. The IESO supports the continuation of development work in order to maintain the viability of the EWT Project with a targeted in-service date by the end of 2020.

The third update report also included the deferral of project costs by staging the installation of station facilities. Staging opportunities have since been studied in more detail and are discussed further in Section 3.

Each assessment and need update report prepared by the IESO confirmed the rationale for the EWT Project and stated that it continued to be the preferred electrical supply option to the Northwest.

2.0 The Government's Order in Council and the Role of the IESO

On March 10, 2016 the former Ontario Minister of Energy, Bob Chiarelli, issued a letter[12] to the Board stating that the EWT Project continues to be the IESO's recommended alternative to maintaining a reliable and cost-effective supply of electricity to Northwestern Ontario for the long term and that the government had accordingly issued an Order in Council[13] ("OIC") declaring that the EWT Project is needed as a priority project. The OIC was issued under the authority of section 96.1(1) of the *Ontario Energy Board Act, 1998* ("OEB Act") and

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[11] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/519575/view/IESO%20_EWTUpdateReport_20151215.PDF

[12] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/521922/view/MOE_Ltr_20160311.PDF

[13] https://www.oeb.ca/oeb/_Documents/Documents/ltr_Ministry_OEB_EW-Tie_Priority_Project_20160310.pdf

specifies an in-service date of 2020. The designation of the Project under section 96.1 of the OEB Act satisfies the usual need requirement for obtaining section 92 approval. The IESO's evidence therefore does not address need. Rather the IESO's evidence addresses its proposal for staging the EWT Station work, which will defer and save costs. The IESO's evidence also addresses the scope of the necessary station work to be completed by Hydro One. Specifically, which aspects of this station work relate directly to the connection of the new transmission circuits and achieve the required east to west transfer capability, and which aspects are needed to address existing issues on the system that are unrelated to the EWT Project.

3.0 Staging of Station Facilities for the East-West Tie Project

In the September 2014 letter to the Board, which recommended the deferral of the in-service date for the EWT Project to 2020, the IESO indicated that the additional time would allow for the optimization of equipment and system design, including the staging of station facilities.

The IESO has since worked with Hydro One to evaluate the technical and economic feasibility of different staging alternatives for the required station facilities. The staging alternatives were developed based on two objectives:

1. Deferring as much station work (e.g., breakers) as possible to later stages in order to defer and save costs.

2. Providing the required transfer capability incrementally and as needed to satisfy reliability needs.

Two staging alternatives were developed and compared based on these objectives: (i) the Twinned Alternative, and (ii) the Multi-Circuit Alternative. The Multi-Circuit Alternative is the recommended staging for the EWT Station work due to its lower overall cost. The two alternatives are described below.

The Twinned Alternative

In the third need update report posted December 15, 2015, the Twinned Alternative was proposed as a possible way of staging the EWT Station work. This alternative consists of two stages. In the initial stage the two new East-West Tie circuits would be bundled together to create one super-circuit and the two existing East-West Tie circuits would be bundled together to create a second super-circuit — i.e., twinned. A twinned circuit, or super-circuit, is formed when two circuits are connected together before they terminate at the station, therefore operating as a single circuit with an enhanced thermal rating. This results in the use of fewer circuit breakers at each station (since the number of East-West Tie circuit terminations at each station is halved) and still provides 450 MW of east to west transfer capability. The second and final stage would involve the separation of the two super-circuits, the installation of the deferred breakers and associated facilities (allowing each individual circuit to be separately terminated), and the addition of a static var compensator ("SVC") to provide the full 650 MW east to west transfer capability. This second stage would not be initiated until it was necessary to deliver the full 650 MW of east to west transfer capacity.

The Multi-Circuit Alternative

The Multi-Circuit Alternative would also consist of two stages. The initial stage would consist of all the station facilities required to separately terminate the new EWT Line circuits and provide 450 MW of east to west transfer capability. In the second stage, the only station facility added would be an SVC to provide the full 650 MW east to west transfer capability.

The IESO and Hydro One performed further work to evaluate the Twinned Alternative since the December 2015 need update and determined that there would be additional work and costs associated with the super-circuit arrangement. These included increased costs for protection and control schemes, costs for intermediate connections for each super-circuit, and further costs to upgrade breakers and the associated connection components to accommodate the higher flows on the twinned circuits. The costs increases to both stages of the Twinned Alternative result in its cost exceeding the cost of the Multi-Circuit Alternative, even when accounting for the increased deferment benefit in the former.

Consequently, while not deferring as many physical assets as in the Twinned Alternative, the Multi-Circuit Alternative demonstrated savings in overall station cost when compared to the Twinned Alternative based on high level estimates provided by Hydro One in Exhibit B, Tab 5, Schedule 1 of their EB-2017-0194 application. This cost differential is principally due to the increased costs which arise from the additional work and upgrades required to defer additional breaker facilities in the Twinned Alternative.

The Multi-Circuit Alternative retains the flexibility to trigger the full east to west transfer capability of 650 MW when it is needed, due to the deferment of the SVC, and it is the lowest cost option. Accordingly, the IESO recommends the Multi-Circuit Alternative over the Twinned Alternative.

Sections 3.1 and 3.2 provide a detailed description of the two stages in the Multi-Circuit Alternative.

3.1 Stage 1

As previously described, the first stage ("Stage 1") would facilitate the connection of the new 230 kV transmission circuits and provide 450 MW east to west transfer capability. Stage 1 also includes facilities to address a high voltage concern which is unrelated to the EWT Project; this is described in more detail later in this section.

Stage 1 of the EWT Station work will entail:

1. Installing new facilities at each of the three terminal stations to terminate the 230 kV circuits of the new EWT Line Project.

2. Reconfiguring existing facilities at Wawa TS and Marathon TS to enable 450 MW east to west transfer while respecting North American Electric Reliability Corporation ("NERC") and Ontario Resource and Transmission Assessment Criteria ("ORTAC"), adequately compensating for the new EWT Line, and bringing the station layouts in compliance with current ORTAC guidelines, providing additional system benefits.

3. Installing additional reactive compensation at Lakehead TS to mitigate the existing high voltage issue.

Hydro One estimates the total cost of the Stage 1 station work at Lakehead TS, Marathon TS and Wawa TS to be $157 million.[14]

Connecting the new EWT Line and re-configuring existing facilities to provide the required 450 MW of east to west transfer capability

Marathon TS and Wawa TS were originally constructed in the early 1970s based on the accepted practices for non-critical stations at that time. As such, they do not follow current ORTAC-prescribed guidelines which provide that station layouts should minimize the number of elements removed from service for a given contingency.

Specifically, the existing Marathon TS and Wawa TS are configured such that each autotransformer, along with the critical voltage control facilities on its tertiary winding, share a common terminal position on the bus with one of the existing 230 kV circuits. This does not meet the ORTAC guideline (B.3.4) which provides that more than one element should not share a common position on a bus. As a result of this configuration not

[14] The estimated $157 M is only for station facilities. As stated in their evidence, Upper Canada Transmission estimates a cost of $740 M for their line facilities which are required to achieve the 450 MW east to west transfer capability.

complying with ORTAC guidelines, simply terminating the new circuits at their respective stations will not be sufficient to achieve the required 450 MW transfer westward while respecting NERC, and ORTAC criteria.

To achieve the transfer capability required for the EWT Project and to perform the necessary upgrades to satisfy ORTAC guidelines, the existing station facilities will need to be reconfigured to separate the autotransformers from the existing 230 kV circuits. Reconfiguration will ensure critical voltage control facilities remain available following contingencies involving the existing EWT circuits and addresses other potential issues, which allows the 450 MW transfer limit to be attained.

In addition to achieving the required 450 MW transfer limit, meeting ORTAC guidelines by separating the autotransformers from the existing circuits will deliver a number of operational benefits. These benefits will include more reliable system conditions during planned and forced outages, and higher real-time operating limits. The cost to reconfigure the station facilities to comply with ORTAC guidelines is estimated to be $40-50 million.

Mitigating the existing high voltage issue at Lakehead

The Northwest system is currently exposed to high voltage conditions for the concurrent outage of both Lakehead TS autotransformers and their tertiary voltage control devices. The loss of this equipment will separate the 230 kV and 115 kV systems and result in excessively high voltages on the 230 kV system. This condition violates NERC reliability standards and the voltage limits prescribed by ORTAC, putting equipment at risk. Currently this issue is being provisionally addressed either by running Atikokan Generating Station ("GS") out of merit or deferring outages. The only other operational measure available to address the issue is removing 230 kV circuits from service which, in this instance, would directly compromise supply reliability.

Running Atikokan GS has not proven to be effective at mitigating the existing post-contingency high voltage issues – accordingly planned outages have often been deferred. Furthermore, for unplanned outage situations, dispatching Atikokan GS out of merit is not a dependable option due to fuel limitations. The IESO has therefore recommended that a 230 kV reactor be installed at Lakehead TS that will remain available whenever both autotransformers are out-of-service. This reactor is needed to meet NERC reliability standards which require the system to be planned and operated in a manner that does not exceed equipment ratings. This high voltage concern is unrelated to the new EWT Line and the work is required in the same time frame, or earlier, irrespective of the EWT Project; however, since work is already being completed at Lakehead TS to connect the new transmission circuits including the reactor as part of the EWT Project, this results in a cost savings of approximately $1.5 million. The estimated cost for the new Lakehead TS reactor as part of the EWT Station Project is $10 million.

The station facilities and modifications required to incorporate the new transmission circuits and achieve the 450 MW east to west transfer capability are shown in Figures 3-1 to 3-3, along with the station facilities required to mitigate the existing high voltage concern at Lakehead TS. The IESO's System Impact Assessment ("SIA") confirmed that these facilities will provide 450 MW east to west transfer capability while respecting NERC and ORTAC criteria.

Figure 3-1: Station Facilities required at Wawa TS for the termination of the new EWT Line and to ensure the required 450 MW east to west transfer capability is achieved

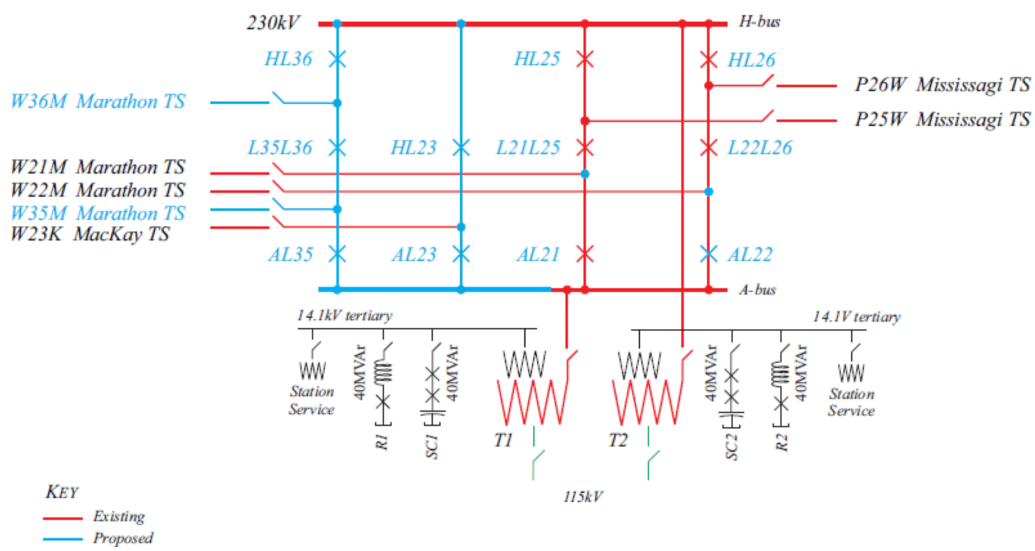


Figure 3-2: Station Facilities required at Marathon TS for the termination of the new EWT Line to ensure the required 450 MW east to west transfer capability is achieved

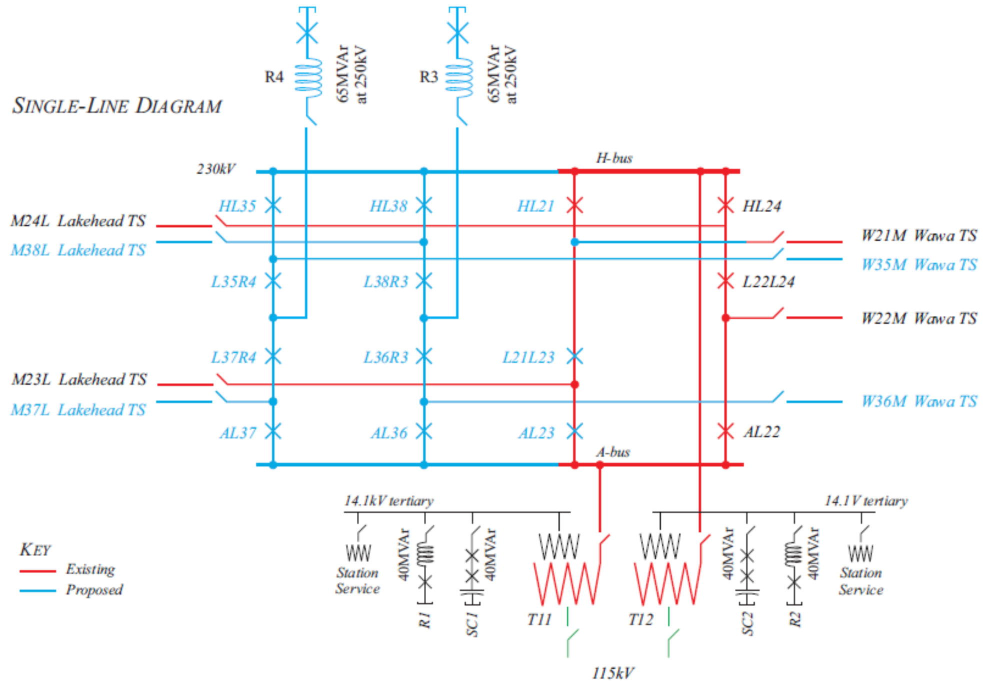
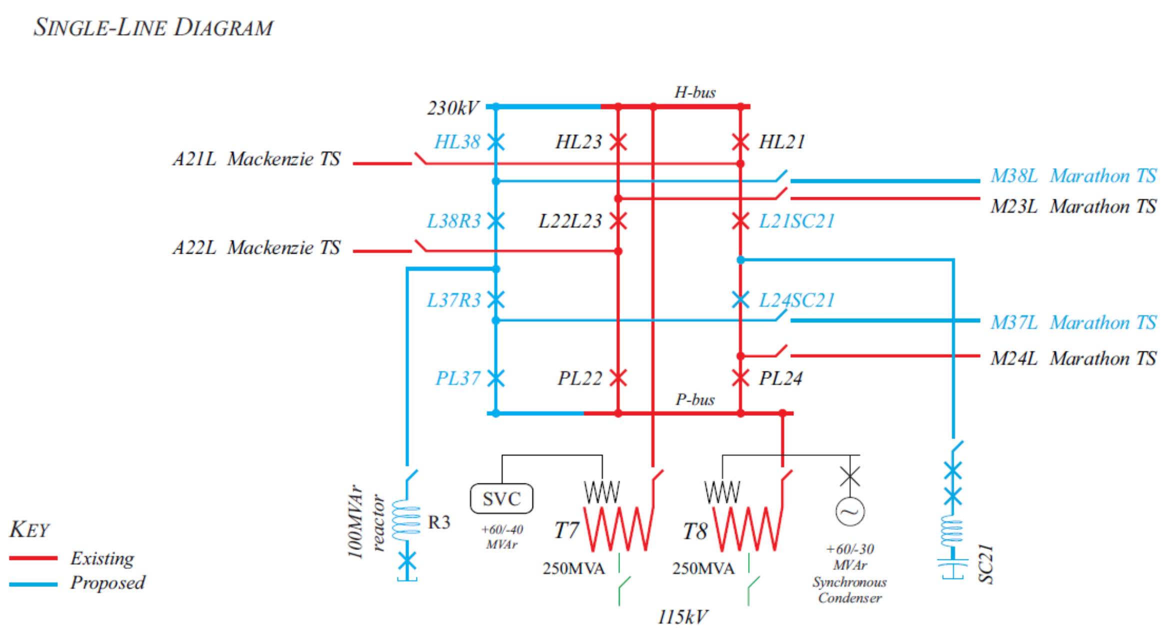


Figure 3-3: Station Facilities required at Lakehead TS for the termination of the new EWT Line, to ensure the required 450 MW east to west transfer capability is achieved, and to mitigate existing high voltage concerns



Due to the rearrangement and addition of circuit breakers and circuits, Stage 1 also includes revisions to the Northwest Remedial Action Scheme ("RAS"). This involves adding to, and modifying, the contingencies in the Northwest RAS and incorporating the ability to trip the new shunt reactors and capacitor bank.

3.2 Stage 2

The second stage ("Stage 2") would enable the full 650 MW of east to west transfer capability when it is needed. This will defer approximately $60 million of station costs to 2024, based on the IESO's most recent need update report, providing approximately $10 million in cost savings.

The station work required for Stage 2 primarily consists of:

1. The installation of an SVC at Marathon TS, with the associated breaker and disconnect switches needed for connection.
2. Additions and revisions to the relevant protection and control systems, including the Northwest RAS.

In addition to this station work, sections of Hydro One's 115 kV circuits A5A and T1M between Alexander Switching Station and Marathon TS will need to be upgraded to achieve a transfer capability of 650 MW. No upgrades of the new 230 kV transmission circuits would be required to obtain the 650 MW rating.

4.0 Costs for Station Facilities

The IESO has identified a staged implementation for the station facilities needed to connect the new transmission circuits for the EWT Project, to provide the required east to west transfer capability, and improve voltage control of the existing system. The IESO's staging plan provides cost benefit to ratepayers by deferring Stage 2 investments until the full 650 MW transfer capability is required.

A summary of Hydro One's station cost breakdown is summarized below in Table 1 below.

Table 1 Station Costs for the EWT Project

Stage	Description	Hydro One's Estimated Cost
EWT Stage 1	Facilities required to address the existing high voltage problem at Lakehead TS	$10 M
	Facilities required for the connection of new transmission circuits to achieve the full 450 MW east to west transfer capability and to bring stations into compliance with ORTAC guidelines	$147 M
	Total for Stage 1	$157 M
EWT Stage 2	Installation of additional equipment (SVC) to increase east to west transfer capability to 650 MW	$60 M[15]
	Total for future commitment	$60 M

[15] Does not include the cost for the 115 kV line upgrades (A5A and T1M) which is estimated to be approximately $1 M.

Project Classification and Categorization

Project Classification

Per the Board's filing guidelines, rate-regulated projects are classified into three groups based on their purpose.

- Development projects are those which:
  - (i) provide an adequate supply capacity and/or maintain an acceptable or prescribed level of customer or system reliability for load growth or for meeting increased stresses on the system; or
  - (ii) enhance system efficiency such as minimizing congestion on the transmission system and reducing system losses.
- Connection projects are those which provide connection of a load or generation customer or group of customers to the transmission system.
- Sustainment projects are those which maintain the performance of the transmission network at its current standard or replace end-of-life facilities on a "like for like" basis.

Based on the above criteria, the East-West Tie Project, consisting of the EWT Line Project and the EWT Station Project, is a Development project.

Expansion of the transmission system connecting the northeast and northwest regions of Ontario is driven by a) the forecast growth in demand, mainly from the mining sector, and connection of the remote communities of the North-of-Dryden sub-region, and b) the requirement to satisfy obligations specified by NERC and the Independent Electricity System Operator (IESO) with respect to the reliability of the Bulk Electric System and the voltage control requirements in the East-West Tie Project's area.

The east-west power transfer capability of the existing transmission system is 155-175 MW[1]. The IESO has recommended the expansion of the East-West Tie by a new 230 kV double-circuit transmission line, as well as required facilities at the terminal stations, in order to increase the transfer capability to 450 MW in the short-term and to 650 MW in the mid-term, depending on the timing of mining and other developments.

The East-West Tie Project will provide 450 MW transfer capability in the interim period, increasing to 650 MW when the need arises, while meeting the performance requirements of the TPL-001-4 standard of NERC (in particular, respecting double-circuit and breaker-failure contingencies) and the Ontario Resource and Transmission Assessment Criteria of the IESO.

Project Categorization

The Board's filing guidelines require that projects be categorized to distinguish between a project that is a "must-do", which is beyond the control of the applicant ("non-discretionary"), from a project that is at the discretion of the applicant ("discretionary"). Non-discretionary projects may be triggered or determined by such things as:

a) mandatory requirement to satisfy obligations specified by regulatory organizations including NPCC/NERC or by the IESO;
b) a need to connect new load (of a distributor or large user) or new generation connection;
c) a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
d) projects identified in a provincial government approved plan;
e) projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and

[1] The IESO's Third Update Report [Exhibit B, Tab 2, Schedule 1, Attachment 1] has specified the current East-West transfer capability as 155 MW in summer and 175 MW in winter.

f) a need to comply with direction from the Ontario Energy Board in the event it is determined that the transmission system's reliability is at risk.

Based upon the above criteria, the EWT Station Project, which is a transmission interconnection, is considered non-discretionary. The EWT Station Project is being undertaken in response to:

- the mandatory requirement to satisfy obligations specified by NERC and the IESO,
- the need to maintain acceptable voltages before and after contingencies, and
- the provincial government approved 2013 Long-Term Energy Plan and the 2016 Order-in-Council that identified the East-West Tie expansion as a priority project.

Categorization and Classification

		Project Need	
		Non-discretionary	Discretionary
Project Class	Development	**X**	

Cost-Benefit Analysis and Options

This evidence discusses alternatives that were considered with respect to the EWT Station Project.

To support the targeted 650 MW east-west power transfer capability, while meeting the design and reliability requirements of the applicable standards and criteria[1], the initial scope of the Project had specified the following for the EWT Station Project:

- Connection of the new EWT lines and reconnection of some of the existing 230 kV transmission lines at Wawa Transformer Station (TS), Marathon TS and Lakehead TS with the addition of new 230 kV circuit breakers and switches and associated protection, control and telecommunication facilities ,
- Addition of voltage support devices (reactive resources), including a Static Var Compensator (SVC) at Marathon TS, and
- Increasing the thermal rating of the sections of the 115 kV transmission lines (circuits A5A and T1M) which parallel the EWT lines.

The IESO's Third Update Report to the OEB[2] identified a potential opportunity to stage the installation of station facilities and defer a portion of the costs to 2024. Following this report, Hydro One and the IESO investigated the options for staging the station facilities. Two alternatives were compared: the twinned alternative, similar to what was proposed in the IESO's update report, and the multi-circuit alternative. These two alternatives are described in more detail in the following sections. Both alternatives consist of an initial stage, which provides 450 MW transfer capability, and a second stage to enable the full 650 MW transfer capability when needed (expected to materialize in 2024 based on analysis in the IESO's need update report).

[1] The planning standards and criteria of the North American Electric Reliability Corporation (NERC) and the IESO, including ORTAC, apply to the East-West Tie Project.
[2] Exhibit B, Tab 2, Schedule 1, Attachment 1.

Alternative 1 – Twinned Alternative: This alternative consists of two stages. In Stage 1, the two circuits of the new EWT lines are twinned (bundled together) to form a single super-circuit and, similarly, the two circuits of the existing EWT lines are also twinned to form another super-circuit. This results in the need for fewer circuit breakers at each station. Later, in Stage 2, the twinned circuits are separated from each other to convert the two super-circuits back to four individual circuits. These two stages are described in more detail in the following.

Stage 1, which would be in-service by November 2020 and provide 450 MW transfer capability, consists of:

- Joining the two circuits of the new EWT transmission lines together and joining the two circuits of the existing East-West Tie transmission lines together at four or more locations along the lines to form two super-circuits between Wawa TS, Marathon TS and Lakehead TS,
- Connecting the two super-circuits to the three stations by installing required 230 kV circuit breakers and other facilities,
- Installing 230 kV shunt reactors at Marathon TS and Lakehead TS,
- Installing a 230 kV capacitor bank at Lakehead TS, and
- Making necessary upgrades to the bus work and terminal facilities at all three stations to support the high current of the super-circuits.

Stage 2, which provides the 650 MW of transfer capability, would be completed in the future when the additional capability is required, consists of:

- Separating the two super-circuits into their original four circuit arrangement,
- Installing additional 230 kV circuit breakers and other facilities to connect these four circuits individually at the three stations, and
- Installing the static var compensator (“SVC”) and upgrading the 115 kV lines.

Both stages require installations and revisions of protection and control facilities. They also require revisions of the Northwest Remedial Action Scheme, which involves adding new contingencies and revising the existing contingencies detected by the scheme, according to the added and revised circuit connections.

Alternative 2 – Multi-Circuit Alternative: In this alternative, which also has two stages, the new EWT lines are connected individually to the stations from the beginning. In Stage 1 circuit breakers and other facilities are installed to connect the new EWT lines and revise the connection of some of the existing lines (i.e. reconfigure the stations). Only the installation of the SVC and upgrade of the 115 kV lines are deferred to Stage 2. These two stages are described in more detail in the following.

Stage 1, which would be in-service by November 2020 and provide 450 MW transfer capability, consists of:

- Connecting the new EWT lines to the three stations by installing the required 230 kV circuit breakers and other facilities,
- Reconnecting five of the existing lines at two stations by installing required 230 kV circuit breakers and other facilities,
- Installing 230 kV shunt reactors at Marathon TS and Lakehead TS,
- Installing a 230 kV capacitor bank at Lakehead TS, and
- Upgrading the bus work and terminal facilities at all three stations to support the eventual 650 MW transfer capability.

Stage 2, which provides 650 MW of transfer capability would be completed in the future when the additional capability is required, consists of:

- Installing the SVC and upgrading the 115 kV lines.

Stage 1 requires installations and revisions of protection and control facilities and revisions of the Northwest Remedial Action Scheme, which involves adding new contingencies and revising the existing contingencies detected by the scheme, according to the added and revised circuit connections. Stage 2 requires installation of protection and control facilities related to the SVC.

The IESO evidence, filed as **Exhibit B, Tab 3, Schedule 2** provides further description of the above staging options and alternatives.

<u>Preferred Alternative</u>

Comparison of the two alternatives showed that the multi-circuit alternative (Alternative 2) is the lower cost option and that it avoids technical challenges and implementation risks of the twinned alternative (Alternative 1). Therefore, Alternative 2, the Multi-Circuit Alternative, is the preferred alternative, based on both technical and financial considerations

Although Stage 1 of Alternative 1 (Twinned Alternative) requires fewer 230 kV circuit breakers compared to Alternative 2 and defers some of the costs to Stage 2, it will result in higher overall cost. The higher cost results from:

i) additional labour and equipment costs from bundling and unbundling the circuits and connecting and reconnecting of the circuits at the stations; and

ii) upgrading and replacing the terminal facilities of the super-circuits, required to provide sufficient capability for the doubled current in these circuits.

Alternative 1 also has additional technical challenges, including those involving the existing connection of a wind farm to two separate circuits of the East-West transmission lines, which would become one super-circuit. Avoiding the potential need to modify the connection of the wind farm is another benefit of proceeding with Alternative 2.

The following table summarizes the comparison of the two above alternatives.

Comparison Criterion	**Alt. 1 Twinned Alternative**	**Alt. 2 Multi-Circuits Alternative**
Estimated Increased cost	~$40 million	-
Estimated Increased cost – NPV	~$19 million	-
Meets interim and long-term supply needs	Yes	Yes
Implementation risks	High	Low

Note: the above cost comparison is based on the 2014 estimated cost of the original plan. The estimated cost of the final plan has been revised since then, based on the revised station facilities.

The staging in Alternative 2, as described above, allows for approximately $60 million of the station facilities (mainly the SVC) costs to be deferred, resulting in approximately $10 million in net present value cost savings.

Qualitative Benefits of the Project

The EWT Station Project does not contribute any significant qualitative benefits that have not already been captured in the EWT Line Project evidence submitted by NextBridge.

Apportioning Project Costs & Risks

The estimated capital cost of the EWT Station Project, including overheads and capitalized interest is shown below:

Table 1: Cost of Station Work

	Estimated Cost ($000s)
Materials	51,337
Labour	56,895
Equipment Rental & Contractor Costs	8,920
Sundry	1,305
Contingencies	19,227
Overhead [1]	13,367
Allowance for Funds Used During Construction [2]	6,264
Total Station Work	**$157,315**

The cost of the station work provided above allows for the schedule of approval, design and construction activities provided in **Exhibit B, Tab 11, Schedule 1**.

[1] Overhead costs allocated to the project are for corporate services costs. These costs are charged to capital projects through a standard overhead capitalization rate. As such they are considered "Indirect Overheads". Hydro One does not allocate any project activity to "Direct Overheads" but rather charges all other costs directly to the project.

[2] Capitalized interest (or AFUDC) is calculated using the Board's approved interest rate methodology (EB-2006-0117) to the projects' forecast monthly cash flow and carrying forward closing balance from the preceding month.

1.0 RISKS AND CONTINGENCIES

As with most projects, there is some risk associated with estimating costs. Hydro One's cost estimate includes an allowance for contingencies in recognition of these risks.

Based on past experience, the estimate for this project work includes allowances in the contingencies to cover the following potential risks:

- Delays in obtaining required approvals including environmental approvals and Section 92;
- Delays in obtaining partial funding to continue detail engineering and procurement of long lead materials;
- Outage availability risk[3]; a possibility of forced outage due to aging equipment and equipment failure. Based on recent trends, Hydro One has seen two cases of breaker failure and a subsequent switch failure on projects. This Project has a direct impact to OPG; there is a risk that OPG may cancel outages based on historic trend;
- Material delivery delay due to tendering process, procurement or vendor issues;
- Soil conditions across expansion areas on Marathon TS have been assumed identical to the ones specified in the existing soil report;
- NextBridge dead-end structure is not designed to Hydro One clearance standards.

Cost contingencies that have not been included, due to the unlikelihood or uncertainty of occurrence, include:

- Labour disputes;
- Safety or environmental incidents;
- Significant changes in costs of materials since the estimate preparation;

[3] Summer and winter outages may not be available since the circuit may be operating at full capacity.

- Any other unforeseen and potentially significant event/occurrence.

2.0 COSTS OF COMPARABLE PROJECTS

The OEB Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 4, requires the Applicant to provide cost information for a comparable project constructed by the Applicant. For station cost comparisons, Table 2 below shows the cost, construction and technical comparisons of the EWT Station Project, consisting of works at Wawa TS, Marathon TS and Lakehead TS, to the recently constructed Orangeville TS in Central Ontario.

For the purpose of context, Orangeville TS is a 230kV switching and a 230/44kV DESN station with six feeders and two capacitor banks which was completed and placed in-service in December 2014. This Project was chosen as a similar project to each station involved in EWT Station Project because of its similar construction conditions and design. Key project information on the projects is provided in Table 2 below. Notwithstanding the geographical difference, the main drivers of the variance in costs between the projects is the additional work on the EWT Station Project such as new relay buildings, shunt reactors, shunt capacitor banks and the timing between the two project in-service dates, as the EWT Station Project will be placed into service seven years after Orangeville TS.

Table 2: Costs of Comparable Station Projects

Project	**Orangeville TS Station Reconfiguration (actual)**	**Wawa TS Station Expansion (Estimate)**	**Marathon TS Station Expansion (Estimate)**	**Lakehead TS Station Expansion (Estimate)**
Technical	Replace existing (6) 230kV air blast breakers with SF6 and add (3) 230kV circuit and reconfigure 230kV switchyard, AC/DC station service	Add (6) 230 kV circuit breakers + 2 new diameter, 12 disconnect switches, New Relay building	Add (10) 230 kV circuit breakers + 2 new diameter, 20 disconnect switches, New Relay building, (2) 230kV shunt reactors	Add (5) 230 kV circuit breakers + 1 new diameters, 10 disconnect switches, New Relay building, (1) 230kV shunt reactor, (1) 230kV cap bank
Length (km)	N/A	N/A	N/A	N/A
Project Surroundings	Mostly rural	Mostly rural	Mostly rural	Mostly rural
In-Service Date	2014-12	2021-11	2021-11	2021-11
Total Project Cost	$35,000k	$44,850k	$61,530k	$50,935k
Less: Non-Comparable Costs				
Special protection scheme		$1,378k	$836k	$1,205k
230kV line connection to NextBridge		$633k	$358k	$231k
Shunt reactors/cap bank cost			$11,877k	$12,607k
New relay building		$3,200k	$3,200k	$2,300k
Add: Non-Comparable Costs				
Escalation Adjustment (2%/year)	$4,900k			
Total Comparable Project Costs	$39,900k	$39,639k	$45,259k	$34,592k

Connection Projects Requiring Network Reinforcement

The East-West Tie Project is a not a connection project, as defined in the Board's filing guidelines, and will not require network reinforcement as defined in section 6.3.5 of the Transmission System Code.

Transmission Rate Impact Assessment

1.0 ECONOMIC FEASIBILITY

The proposed transmission refurbishment work for the EWT Station Project comprises station assets, which are included in the Network pool for cost classification purposes, with no capital contribution required. See Exhibit B, Tab 2, Schedule 1, for information on the proposed work.

A 25-year illustrative discounted cash flow analysis is provided in Table 3. The results show that based on the estimated initial cost of $157.3[1] million, plus assumed ongoing operating and maintenance costs, the EWT Line Project will have a negative net present value of $153.1 million. This project will not bring any incremental load and therefore, no incremental revenue is forecast.

2.0 RATE IMPACT ASSESSMENT

The analysis of the network pool rate impacts has been carried out on the basis of Hydro One's approved transmission revenue requirement for the year 2016, and the most recently approved Ontario Transmission Rate schedules. The 2017 transmission revenue requirement was not approved by the OEB at the time of the analysis. The impact of the assessment, however, is expected to be similar. The line connection pool and transformation connection pool revenue requirements would be unaffected by the new reinforcement facilities, as there are no project costs allocated to these pools.

[1] Initial costs of $157.3 million include $155 million of up-front capital costs plus $2.3 million cost of removals. $113.4 million will be in-service in 2020 and additional $41.5 million – in 2021

Network Pool

Based on the project's initial cost of $157.3 million and the associated network pool incremental cash flows, there will be a change in the network pool revenue requirement once the project's impacts are reflected in the transmission rate base at the projected in-service date, November 15, 2020. Over a 25-year time horizon, the network pool rate will rise by 5 cents/kw/month, from the current rate of $3.66/kW/month to $3.71/kW/month. The maximum revenue shortfall related to the proposed network facilities will be $13.4 million in the year 2027. This will result in a maximum rate impact of 1.37% in that year. The detailed analysis illustrating the calculation of the incremental network revenue shortfall and rate impact is provided in Table 1 below.

Impact on a Typical Residential Customer in Ontario

Adding the costs of the new facilities to the network pool will cause a slight increase in a typical residential customer's rates. Table 1 below shows the impact for a typical residential customer who is under the Regulated Price Plan (RPP).

Table 1

A. Typical monthly bill (Residential R1 in a high density zone at 1,000 kWh per month with winter commodity prices.)	$188.28 per month
B. Transmission component of monthly bill (based on currently approved Network service rate of $0.0068/kWh & Line and Transformation service rate of $0.0048/kWh)	$13.19 per month
C. Network Pool share of Transmission component	$6.95 per month
D. Impact on Network Pool Provincial Uniform Rates (Table 1)	1.37%
E. Increase in Transmission costs for typical monthly bill (C x D)	$0.09 per month or $1.14 per year
F. Net increase on typical residential customer bill (E / A)	0.05%

Note: Values rounded to two significant digits.

Impact on a Typical Thunder Bay Residential Customer

Adding the costs of the new facilities to the network pool will cause a slight increase in a typical Thunder Bay residential customer's rates. Table 2 below shows the impact for a typical Thunder Bay residential customer who is under the Regulated Price Plan (RPP).

Table 2

A. Typical monthly bill (Residential R1 in a high density zone at 1,000 kWh per month with winter commodity prices.)	$125.62 per month
B. Transmission component of monthly bill (based on currently approved Network service rate of $0.0061/kWh & Line and Transformation service rate of $0.0046/kWh)	$8.30 per month
C. Network Pool share of Transmission component	$4.73 per month
D. Impact on Network Pool Provincial Uniform Rates (Table 1)	1.37%
E. Increase in Transmission costs for typical monthly bill (C x D)	$0.06 per month or $0.78 per year
F. Net increase on typical residential customer bill (E / A)	0.05%

Note: Values rounded to two significant digits.

Table 3 – Revenue Requirement and Network Pool Rate Impact, page 1

Revenue Requirement and Network Pool Rate Impact **(Before Capital Contribution)**

East-West Tie Line Project		Project YE 15-Nov	15-Nov	15-Nov	15-Nov	15-Nov	15-Nov	15-Nov	15-Nov	15-Nov	15-Nov	15-Nov	15-Nov
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Calculation of Incremental Revenue Requirement ($000)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	15-Nov-20												
Capital Cost	113,498												
Less: Capital Contribution Required	-												
Net Project Capital Cost	113,498												
Average Rate Base		75,950	150,351	147,253	144,155	141,057	137,959	134,861	131,763	128,665	125,567	122,469	119,371
Incremental OM&A Costs		448	448	448	448	448	897	897	897	897	897	897	897
Grants in Lieu of Municipal tax		475	475	475	475	475	475	475	475	475	475	475	475
Depreciation		3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098
Interest and Return on Rate Base		4,963	9,824	9,622	9,419	9,217	9,014	8,812	8,610	8,407	8,205	8,002	7,800
Income Tax Provision		(111)	(1,180)	(878)	(604)	(354)	(128)	77	262	429	579	714	835
REVENUE REQUIREMENT PRE-TAX		**8,873**	**12,665**	**12,765**	**12,837**	**12,884**	**13,356**	**13,359**	**13,341**	**13,306**	**13,254**	**13,186**	**13,105**
Incremental Revenue		0	0	0	0	0	0	0	0	0	0	0	0
SUFFICIENCY/(DEFICIENCY)		**(8,873)**	**(12,665)**	**(12,765)**	**(12,837)**	**(12,884)**	**(13,356)**	**(13,359)**	**(13,341)**	**(13,306)**	**(13,254)**	**(13,186)**	**(13,105)**
	Base Year												
Network Pool Revenue Requirement including sufficiency/(deficiency)	928,814	937,688	941,479	941,579	941,651	941,698	942,170	942,173	942,155	942,120	942,068	942,001	941,919
Network MW	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768
Network Pool Rate ($/kw/month)	3.66	3.70	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
RATE IMPACT relative to base year		**1.09%**	**1.4%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**

Assumptions		
Incremental OM&A		Years 1 to 5 0.4% of Initial Capital each year; Years 6 to 15 0.8% of Initial Captial each year; Years 16 to 25 0.99% of Initial Capital each year.
Grants in Lieu of Municipal tax	0.42%	Transmission system average
Depreciation	2.00%	Reflects 50 year average service life for towers, conductors and station equipment, excluding land
Interest and Return on Rate Base	6.53%	Includes OEB-approved ROE of 9.19%, 1.65% on ST debt, and 4.99% on LT debt. 40/4/56 equity/ST debt/ LT debt split
Income Tax Provision	26.50%	2016 federal and provincial corporate income tax rate
Capital Cost Allowance	8.00%	100% Class 47 assets except for Land

Table 3 – Revenue Requirement and Network Pool Rate Impact, page 2

Revenue Requirement and Network Pool Rate Impact **(Before Capital Contribution)**

East-West Tie Line Project		15-Nov 2033	15-Nov 2034	15-Nov 2035	15-Nov 2036	15-Nov 2037	15-Nov 2038	15-Nov 2039	15-Nov 2040	15-Nov 2041	15-Nov 2042	15-Nov 2043	15-Nov 2044	15-Nov 2045
Calculation of Incremental Revenue Requirement ($000)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	15-Nov-20													
Capital Cost	113,498													
Less: Capital Contribution Required	-													
Net Project Capital Cost	113,498													
Average Rate Base		116,274	113,176	110,078	106,980	103,882	100,784	97,686	94,588	91,490	88,392	85,294	82,196	79,098
Incremental OM&A Costs		897	897	897	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121
Grants in Lieu of Municipal tax		475	475	475	475	475	475	475	475	475	475	475	475	475
Depreciation		3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098	3,098
Interest and Return on Rate Base		7,597	7,395	7,193	6,990	6,788	6,585	6,383	6,181	5,978	5,776	5,573	5,371	5,168
Income Tax Provision		943	1,039	1,124	1,199	1,265	1,322	1,372	1,414	1,449	1,479	1,502	1,521	1,535
REVENUE REQUIREMENT PRE-TAX		**13,011**	**12,904**	**12,787**	**12,884**	**12,747**	**12,602**	**12,449**	**12,288**	**12,121**	**11,948**	**11,770**	**11,586**	**11,397**
Incremental Revenue		0	0	0	0	0	0	0	0	0	0	0	0	0
SUFFICIENCY/(DEFICIENCY)		**(13,011)**	**(12,904)**	**(12,787)**	**(12,884)**	**(12,747)**	**(12,602)**	**(12,449)**	**(12,288)**	**(12,121)**	**(11,948)**	**(11,770)**	**(11,586)**	**(11,397)**
	Base Year													
Network Pool Revenue Requirement including sufficiency/(deficiency)	928,814	941,825	941,718	941,601	941,698	941,561	941,416	941,263	941,103	940,936	940,763	940,584	940,400	940,211
Network MW	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768	253,768
Network Pool Rate ($/kw/month)	3.66	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
RATE IMPACT relative to base year		**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**	**1.37%**

1 *Table 4 – DCF Assumptions*

Hydro One Networks -- Transmission Connection Economic Evaluation Model
2016 Parameters and Assumptions

Transmission rates are based on current OEB-approved uniform provincial transmission rates.

Monthly Rate ($ per kW)	
Network	3.66

Grants in lieu of Municipal tax (% of up-front capital expenditure, a proxy for property value):		0.42%	Based on Transmission system average
Income taxes:			
Basic Federal Tax Rate - % of taxable income:	2016	15.00%	Current rate
Ontario corporation income tax - % of taxable income:	2016	11.50%	Current rate
Capital Cost Allowance Rate:			
Class 47 costs	2016	8%	Current rate
Decision Support defined costs (1)	2016	0%	
Decision Support defined costs (2)	2016	0%	
Decision Support defined costs (3)	2016	0%	
After-tax Discount rate:		5.78%	Based on OEB-approved ROE of 9.19% on common equity and 1.65% on short-term debt, 4.99% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5%

Other Assumptions:

Estimated Incremental OM&A: Project specific ($ k):

Network Switching Station	0.40%	of up-front capital expenditure each year for years 1 - 5
	0.79%	of up-front capital expenditure each year for years 6 - 15
	0.99%	of up-front capital expenditure each year for years 16 - 25

2

Deferral Account Requests

Hydro One confirms that no new deferral account is being requested as part of this Application.

On July 12, 2012, in a Decision and Order issued under EB-2012-0180, the Board granted Hydro One permission to record incremental costs related to the East-West Tie Line Designation Proceeding (EB-2011-0140) in the following new sub-accounts of deferral account (Account 1508) in accordance with the provisions of the decision effective March 22, 2012:

- Account 1508, Other Regulatory Assets, Sub-account EWTDA -Support Costs for OEB Designation Process; and
- Account 1508, Other Regulatory Assets, Sub-account EWTDA -Development Work Associated with Stations and Other Supporting Asset Expenditures.

Costs will continue to be recorded and tracked to both these sub-accounts in accordance with the Accounting Order issued on August 2, 2012 (See Attachment 1 to this Exhibit). As at December 31, 2016, approximately $2.8 million has been tracked in the EWT Deferral account (Account 1508-Development Work Associated with Stations and Other Supporting Asset Expenditures).

Hydro One recognizes that to recover any expenditures, the costs must meet the Board's eligibility criteria for regulatory account disposition of prudency, materiality and need.

Further, Hydro One confirms that at the appropriate time in a future Transmission rate filing, it will bring forward any costs for disposition.

Ontario Energy Board | **Commission de l'énergie de l'Ontario**

Ontario

EB-2012-0180

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S. O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an application by Hydro One Networks Inc. to Establish a Deferral Account Related to the East-West Tie Line Proceeding (EB-2011-0140).

BEFORE: Cynthia Chaplin
Vice Chair and Presiding Member

Cathy Spoel
Member

ACCOUNTING ORDER
August 2, 2012

On March 22, 2012 Hydro One Networks Inc. ("HONI") filed an application for an accounting order authorizing it to establish a new deferral account, the East-West Tie deferral account ("EWTDA"). The purpose of the EWTDA is to record expenses relating to the East-West Tie Line proceeding (EB-2011-0140, also referred to as the "Designation Proceeding") and subsequent connection project-related activities related to the new electricity transmission line.

On July 12, 2012, the Board issued its Decision and Order on the application. Therein, the Board granted, with conditions, HONI's request to establish a deferral account, with two sub-accounts, for two cost categories: Support Costs for OEB Designation Process; and Development Work Associated with Stations and Other Supporting Assets. The Board also directed that HONI may record these costs in the following new deferral sub-accounts, effective March 22, 2012:

- Account 1508, Other Regulatory Assets, Sub-account EWTDA - Support Costs for OEB Designation Process; and
- Account 1508, Other Regulatory Assets, Sub-account EWTDA - Development Work Associated with Stations and Other Supporting Asset Expenditures.

In that July 12 Decision, the Board cautioned that the establishment of these two deferral sub-accounts does not guarantee that the amounts collected therein will be automatically disposed, consistent with the principles underlying all Board-approved deferral accounts. In regard to Sub-account EWTDA - Support Costs for OEB Designation Process, the Board further indicated that:

- it does not expect that HONI will seek to recover any costs related to the provision of information prior to July 12, 2012 (the decision date) in the Designation Proceeding, including the information which the Board ordered HONI to produce. The Board will also review these costs for materiality and prudence when HONI requests disposition of this account.
- it acknowledges HONI's proposal to track incremental costs via time tracking sheets to record the number of hours worked and to have these documents made available upon request. The Board also indicated agreement with Board staff's proposal that HONI be required to keep a log of consultant reports and associated costs, so that such information is readily available in the future.

HONI filed a draft Accounting Order on July 19, 2012, and filed an amendment to it on July 20 by attaching the detailed accounting entries for the two approved deferral sub-accounts as Attachment A to that draft. No party filed any comments on the draft Accounting Order.

THE BOARD ORDERS THAT:

1. The Accounting Order set out in Appendix "A" of this Order is approved effective March 22, 2012.

DATED at Toronto, August 2, 2012

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

TO ACCOUNTING ORDER

Hydro One Networks Inc.

EB-2012-0180

DATED: August 2, 2012

HYDRO ONE NETWORKS INC.
TRANSMISSION ACCOUNTING ORDER

Hydro One Networks Inc. Transmission (Hydro One Transmission) received permission (EB-2012-0180) to record incremental costs related to the East-West Tie Designation Proceeding (EB-2011-0140) in two new sub-accounts of Deferral Account 1508 on July 12, 2012.

Hydro One Transmission will establish the following **two new sub-accounts effective March 22, 2012:**

1. Sub-Account EWTDA-Support Costs for OEB Designation Process

Hydro One Transmission will establish a new sub-account *East West Tie Deferral Account ("EWTDA") – Support Costs for OEB Designation Process* to track incremental support costs relating to the EWT designation process and any costs related to station development work prior to the designation of a transmitter.

The account shall be established as Account 1508, Other Regulatory Assets, sub-account 'EWTDA-Support Costs for OEB Designation Process'.

Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

2. Sub-Account EWTDA-Development Work Associated with Stations and Other Supporting Asset Expenditures.

Hydro One Transmission will establish a new sub-account *EWTDA – Development Work Associated with Stations and Other Supporting Asset Expenditures*. Hydro One will track costs related to station development work subsequent to the designation of a transmitter in this sub-account for regulatory purposes. These costs will be captured in sufficient detail for them to be reviewed for prudency when Hydro One requests disposition at a future date.

The account shall be established as Account 1508, Other Regulatory Assets, sub-account 'EWTDA-Development Work Associated with Stations and Other Supporting Asset Expenditures'.

Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

Detailed accounting entries for the above two sub-accounts are attached as Attachment A.

Attachment A

Proposed Accounting Entries

	USofA #	Account Description

1) East West Tie Deferral Account – Support Costs for OEB Designation Process

Dr:	48XX	Operational Transmission Expense account range
Cr:	2205	Accounts Payable

To record preliminary recognition of the support costs for the East West Tie OEB designation process – HONI's costs incurred.

Dr:	1508	Other Regulatory Assets – Sub account "East West Tie Deferral Account – Support Costs for OEB Designation Process"
Cr:	48XX	Operational Transmission Expense account range

To record incremental costs incurred from supporting the OEB in the East West Tie Allocation Proceeding in a deferral account for future disposition (includes consulting, incremental administration and incremental labour).

Dr:	1508	Other Regulatory Assets – Sub account "East West Tie Deferral Account - Support Costs for OEB Designation Process"
Cr:	6035	Other Interest Expense

To record interest improvement on the principal balance of the "East West Tie Deferral Account".

2) **East West Tie Deferral Account – Development Work Associated with Stations and Other Supporting Asset Expenditures**

Dr:	2055	Construction Work in Progress – Electric
Cr:	2205	Accounts Payable

To record HONI's development work associated with stations and other supporting asset expenditures for connection of the East West Tie line.

Dr:	1508	Other Regulatory Asset - Sub account "East West Tie Deferral Account - Development Work Associated with Stations and Other Supporting Asset Expenditures
Cr:	1508	Other Regulatory Asset - Sub account "East West Tie Deferral Account - Development Work Associated with Stations and Other Supporting Asset Expenditures - Contra

Entry to track capital expenditures in the EWTDA.

STAGE 1 PROJECT SCHEDULE

TASK	START	FINISH
Submit Section 92		May 2017
Projected Section 92 Approval	May 2017	March 2018
STATIONS		
Property Rights Acquisition (Wawa TS & Marathon TS)	February 2017	March 2018
Order Station Shunt Reactor for Marathon & Lakehead TS	August 2017	August 2018
Detailed Engineering	February 2017	May 2018
Tender and Award Other Major Station Equipment	May 2018	July 2018
Receive Major Station Equipment	August 2018	February 2019
Construction	May 2018	September 2020
Commissioning	May 2020	November 2020
In-Service		**November 2020**[1]

[1] The in-service date defined in this schedule relates to all undertakings in the EWT Station Project that are necessary for connecting the EWT Line Project. Some work will continue to be done on the three Hydro One stations into Q4 of 2021 to fully utilize the EWT lines and to achieve the 450 MW East-West transfer capability.

Descriptions of the Physical Design

Hydro One is seeking Board leave to construct approval to connect the EWT Line Project to three Hydro One transmission stations, Wawa Transformer Station (TS), Marathon TS and Lakehead TS. The Project will also modify the connection of some of the existing 230 kV lines at Wawa TS and Marathon TS.

1.0 STATION FACILITIES

1.1 Proposed Station Facilities

Hydro One is seeking approval for the following new and upgraded facilities at three existing transmission stations as part of the EWT Station Project:

Wawa TS

Wawa TS is an existing Hydro One 230/115 kV transformer station near the municipality of Wawa. Currently the major 230 kV facilities at the station consist of two 230/115 kV power transformers, five transmission circuits, five circuit breakers, seventeen disconnect and disconnect/ground switches for the transformers, breakers and lines, as well as one relay building.

The EWT Station Project work at Wawa TS includes expanding the property of the station, constructing a new relay building with two relay rooms, installing six new 230 kV SF6 circuit breakers and 230 kV disconnect and ground switches for connecting the new EWT Lines and revising the connection of some of the existing lines, with associated protection, control and telecommunication equipment. See Section 1.2 for more details.

Marathon TS

Marathon TS is an existing Hydro One 230/115 kV transformer station near the town of Marathon. Currently the major 230 kV facilities at the station consist of two 230/115 kV power transformers, four transmission circuits, four circuit breakers, fourteen disconnect and disconnect/ground switches for the transformers, breakers and lines, as well as one relay building.

The EWT Station Project work at Marathon TS includes expanding the property of the station, constructing a new relay building with two relay rooms, installing ten new 230 kV SF6 circuit breakers and new 230 kV disconnect and ground switches for connection of the new EWT Lines, revising the connection of some of the existing lines and installing two 230 kV shunt reactors (65 MVAr each), with associated protection, control and telecommunication equipment. See Section 1.3 for more details.

Lakehead TS

Lakehead TS is an existing Hydro One 230/115 kV transformer station near the City of Thunder Bay. Currently the major 230 kV facilities at the station consist of two 230/115 kV power transformers, four transmission circuits, six circuit breakers, eighteen disconnect and disconnect/ground switches for the transformers, breakers and lines, as well as one control building that houses the relay room.

The EWT Station Project work at Marathon TS includes expanding the perimeter of the station within the existing Hydro One owned property boundaries, constructing a new relay building with one relay room, installing five new 230 kV SF6 Circuit Breakers and new 230 kV disconnect and ground switches for connecting the EWT Line Project and installing one 230 kV shunt reactors (125 MVAr) and one 230 kV shunt capacitor bank (125 MVAr), with associated protection, control and telecommunication equipment. See Section 1.4 for more details.

Northwest Special Protection Scheme:

The recently installed Northwest Special Protection Scheme (SPS) can respond to various contingencies in the Northwest by switching shunt reactors and capacitor banks or, when needed, rejecting load at selected locations to maintain acceptable post-contingency operating conditions. The EWT Station Project includes modification and expansion of this SPS to revise detection of contingencies (according to the revised and expanded station configurations), recognize additional contingencies, and switch the new shunt reactors and capacitor bank.

1.2 Details of the Proposed Station Facilities – Wawa TS

The scope of work at Wawa TS includes the following activities.

(i) Work on existing bus and line exits in the 230 kV switchyard:

- Uprating the two main 230 kV buses of the 230 kV switchyard to a summer rating of not less than 3000A,
- Uprating the ampacity of the existing diameters, in the 230 kV switchyard, to a summer rating of not less than 2000A.

(ii) Work in the 230 kV switchyard:

- Adding one new diameter in Bay IV with three circuit breakers – the new diameter will have a summer rating of not less than 3000A,
- Connecting the two new EWT 230 kV Wawa-Marathon circuits to the new 230 kV diameter. The line exits will have a summer rating of not less than 1660A,
- Adding one new diameter in Bay III with two circuit breakers – the new diameter will have a summer rating of not less than 3000 A,
- Re-terminating circuit W23K from its current position in Bay II into the new diameter in Bay III,
- Re-terminating circuit W21M from its current position in Bay III to Bay II,

- Adding a new 230 kV circuit breaker in the existing diameter in Bay I for termination of circuit W22M,
- Adding twelve new disconnect switches for the above new circuit breakers,
- Adding two new disconnect/ground switches for the new EWT circuits,
- Upgrading two disconnect/ground switches for the existing EWT circuits.

(iii) Upgrading the 600V AC Station Services to the requirements of Hydro One's functional standard.

(iv) Adding a new 250V, 800A DC Station Services Manual Transfer Scheme (MTS) and associated batteries and chargers for supply of all 230 kV protection and control equipment to meet the requirements of Hydro One's functional standard.

(v) Adding a new 230 kV relay building for protection, control, and telecommunication equipment, with two relay rooms, two DC station service rooms, two battery rooms and a small office space. The overall dimensions of the building will be approximately 27x12m.

(vi) Separating all existing and new protection and control equipment and cable routings into two systems.

Exhibit B, Tab 2, Schedule 1, Attachment 2 shows the existing and proposed stage development diagram of the 230 kV switchyard at Wawa TS. The diagram includes the proposed facilities in red.

Additionally, at Wawa TS, Hydro One will complete the following activities in order to connect the EWT Line Project:

1. Connect the new EWT 230 kV Wawa-Marathon circuit W35M from the last dead-end line structure (installed and owned by NextBridge) to the appropriate girder

of the line terminating structure located on the west side of the 230 kV switchyard.

2. Install three steel structures inside the station - on the east side of the 230 kV switchyard - and connect the second new EWT 230 kV Wawa-Marathon circuit W36M from the last structure (installed and owned by NextBridge) to the above steel structures and, from there, to the appropriate girder of the line terminating structure located on the east side of the 230 kV switchyard.

1.3 *Details of the Proposed Station Facilities - Marathon TS*

The Scope of work at Marathon TS includes the following activities.

(i) Work on existing bus and line exits in the 230 kV switchyard:

- Uprating the two main 230 kV buses of the 230 kV switchyard to a summer rating of not less than 3000A,
- Uprating the ampacity of the existing diameters in the 230 kV switchyard to a summer rating of not less than 2000A.

(ii) Work at the 230 kV switchyard:

- Adding two new diameters, each with four circuit breakers; the new diameters will have a summer rating of not less than 3000A,
- Connecting the four new EWT 230 kV Wawa-Marathon and Marathon-Lakehead circuits. The line exits will have a summer rating of not less than 1600A,
- Adding two new 230 kV circuit breakers in the existing diameter in Bay IV for terminating circuit M23L,
- Re-terminating circuit W21M in Bay III,
- Adding twenty new disconnect switches for the above new circuit breakers,
- Adding four new disconnect/ground switches for the new EWT Lines,
- Upgrading four existing disconnect/ground switches for the existing EWT Wawa-

Marathon and Marathon-Lakehead circuits.

(iii) Adding two 230 kV, 65 mVAr, 3-phase shunt reactors, and connect into the new 230 kV diameters with the following:

- One reactor breaker,
- One disconnect switch,
- One surge arrestor,
- One surge capacitor.

(iv) Upgrading the 600V AC Station Services to meet the requirements of Hydro One's functional standard.

(v) Upgrading the 250V DC Station Services to the meet requirements of Hydro One's functional standard.

(vi) Adding a new 230 kV relay building for protection, control, and telecommunication equipment, with two relay rooms, two DC station service rooms and two battery rooms. The overall dimensions of the building will be approximately 22x15 m.

(vii) Separating all existing and new protection and control equipment and cable routings into two systems.

Exhibit B, Tab 2, Schedule 1, Attachment 3 shows the existing and proposed stage development diagram of the 230 kV and 115 kV switchyards at Marathon TS. The proposed diagram includes the proposed facilities in red.

Additionally, at Marathon TS, Hydro One will complete the following activities in order to connect the EWT Lines Project:

1. Connect the two new EWT 230 kV Marathon-Lakehead circuits M37L and M38L and two new EWT 230 kV Wawa-Marathon circuits W35M and W36M from their

last dead-end line structures (installed and owned by NextBridge) to the appropriate girders of the line termination structures in the 230 kV switchyard.

1.4 Details of the Proposed Station Facilities - Lakehead TS

The Scope of work at Lakehead TS includes the following activities.

(i) Existing bus work and line exits in the 230 kV switchyard east:

- Uprating the two main 230 kV buses of the 230 kV switchyard east to a summer rating of not less than 3000A,
- Uprating the ampacity of the existing diameters, in the 230 kV switchyard east, to a summer rating of not less than 2000A,
- Adding four line disconnect/ground combination switches.

(ii) Work at the230 kV switchyard east:

- Adding one new diameter with four circuit breakers in Bay X and IX – the new diameter will have a summer rating of not less than 3000A,
- Adding one new 230 kV circuit breaker to the existing diameter in Bay XIV,
- Connecting the two new EWT 230 kV Marathon-Lakehead circuits to the new diameter - the line exits will have a summer rating of not less than 1600A,
- Adding ten disconnect switches for the new circuit breakers,
- Adding two new disconnect/ground switches for the new EWT Lines,
- Upgrading two existing disconnect/ground switches for the existing EWT circuits.

(iii) Adding a new 230 kV, 125 MVAr shunt capacitor bank and connecting it to the diameter in Bay XIV with the following:

- Two SF6 circuit breakers for capacitor bank switching,
- One disconnect switch,
- One surge arrestor,

- One surge capacitor,
- One series reactor,
- One three-phase and one single-phase two pole ground switch.

(iv) Adding a new 230 kV, 125 MVAr three-phase shunt reactor and connecting it to the new 230 kV diameter in Bay IX with the following:

- One reactor breaker,
- One disconnect switch,
- One surge arrestor,
- One surge capacitor.

(v) Upgrading the 600V AC station services to the requirements of Hydro One's functional standard.

(vi) Upgrading of the 250V DC station services to the requirements of Hydro One's functional standard.

(vii) Adding a new 230 kV relay building for protection, control, and telecommunication equipment, with one Relay Room and an overall dimension of approximately 24x10m.

(viii) Separating all existing and new protection and control equipment and cable routings into two systems in the new and existing relay rooms.

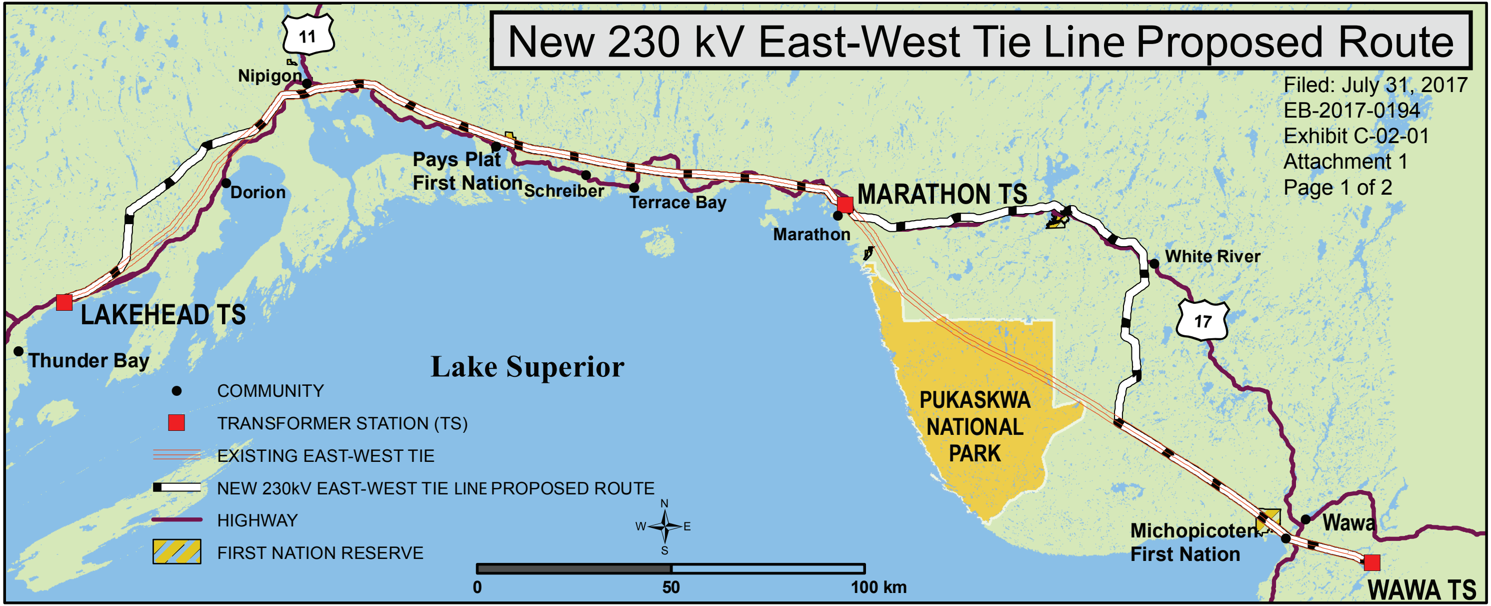
Exhibit B, Tab 2, Schedule 1, Attachment 4 shows the existing and proposed stage development diagram of the 230 kV Switchyard East at Lakehead TS. The diagram includes the proposed facilities in red.

Additionally to connect the EWT Line Project, at Lakehead TS, Hydro One will connect the two new EWT 230 kV Marathon-Lakehead circuits M37L and M38L from the last dead-end line structures (installed and owned by NextBridge) to the appropriate girders of the line termination structures in the 230 kV switchyard.

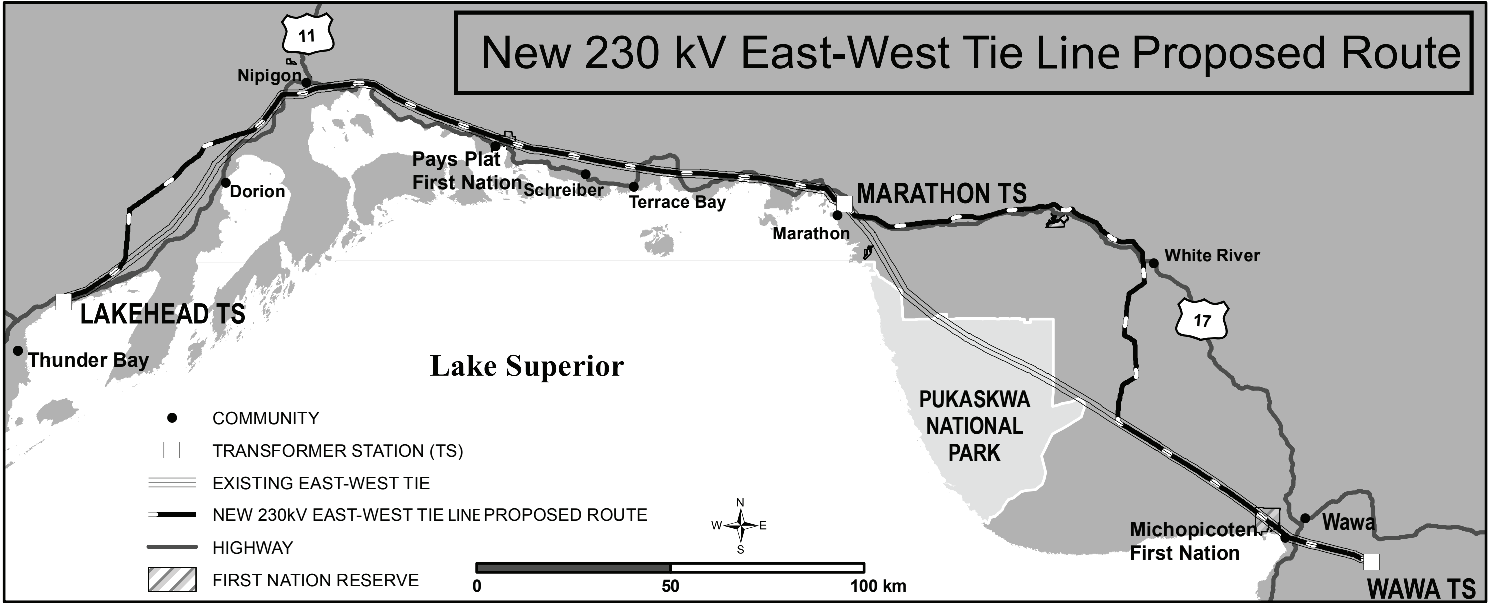
Maps

A map indicating the geographic location of the Project is provided as **Attachment 1**.

This Project proposes to expand Hydro One's property at two existing transformer stations, Wawa TS and Marathon TS. Further details, including diagrams, on land matters are available at **Exhibit E, Tab 1, Schedule 1**.



New 230 kV East-West Tie Line Proposed Route
Filed: July 31, 2017
EB-2017-0194
Exhibit C-02-01
Attachment 1
Page 1 of 2
11
Nipigon
Pays Plat
First Nation
Schreiber
Terrace Bay
Dorion
MARATHON TS
Marathon
White River
17
LAKEHEAD TS
Thunder Bay
Lake Superior
PUKASKWA
NATIONAL
PARK
Wawa
Michipicoten
First Nation
WAWA TS
COMMUNITY
TRANSFORMER STATION (TS)
EXISTING EAST-WEST TIE
NEW 230kV EAST-WEST TIE LINE PROPOSED ROUTE
HIGHWAY
FIRST NATION RESERVE
N
W
E
S
0
50
100 km


New 230 kV East-West Tie Line Proposed Route
11
Nipigon
Pays Plat
First Nation
Schreiber
Terrace Bay
Dorion
MARATHON TS
Marathon
White River
17
LAKEHEAD TS
Thunder Bay
Lake Superior
PUKASKWA
NATIONAL
PARK
Wawa
Michopicoten
First Nation
WAWA TS
COMMUNITY
TRANSFORMER STATION (TS)
EXISTING EAST-WEST TIE
NEW 230kV EAST-WEST TIE LINE PROPOSED ROUTE
HIGHWAY
FIRST NATION RESERVE
N
W
E
S
0
50
100 km

Operational Details

The EWT Station Project proposes to install new facilities, revise the connection of some of the existing facilities, and connect the new EWT double-circuit transmission lines at three Hydro One stations, Wawa TS, Marathon TS and Lakehead TS. The protection, control and telecommunication (PC&T) facilities at these stations will be upgraded and expanded. Hydro One PC&T facilities will continue to protect all elements in the stations as before and also protect the new EWT transmission lines by detecting faults and isolating the faulted elements. Hydro One breakers and switches will be used to switch all the facilities, including the new EWT transmission lines, in and out of service in concurrence with the IESO and the owners of the new transmission lines.

Land Matters

As referenced in the Application, the EWT Station Project will necessitate the need for additional facilities at Lakehead Transformer Station ("Lakehead TS"), Marathon Transformer Station ("Marathon TS"), and Wawa Transformer Station ("Wawa TS"). Station expansion at Marathon TS and Wawa TS requires the fee simple purchase of additional lands adjacent to the current Hydro One properties to accommodate the necessary station upgrades. Hydro One will not need to acquire additional property rights at Lakehead TS to complete the station work as proposed in this Application.

Wawa TS

The current Wawa TS station property is approximately 7.7 acres in size, located about 6.5km south of Provincial Highway 101 in Nebonaionquet Township, southeast of the Town of Wawa. To accommodate the EWT Station Project requirements at Wawa TS, additional lands are required to extend the existing northern boundary of the Hydro One property. The expansion of the station will require the fee simple purchase of approximately 1 acre of land owned by Grant Lake Forest Resources Ltd. ("Grant Lake"), as illustrated in Attachment 1. An early access agreement has been negotiated with Grant Lake to allow Hydro One to proceed with surveying, testing, and site preparation. An Agreement of Purchase and Sale will also be negotiated with Grant Lake for approximately one acre of additional land required at Wawa TS. The form of the agreement is provided as Attachment 2. Access to Wawa TS from Highway 101 crosses a Canadian National Railway ("CN Rail") line. Should crossings need to be upgraded to accommodate the construction equipment required at Wawa TS, Hydro One will negotiate additional crossing permits with CN Rail as required.

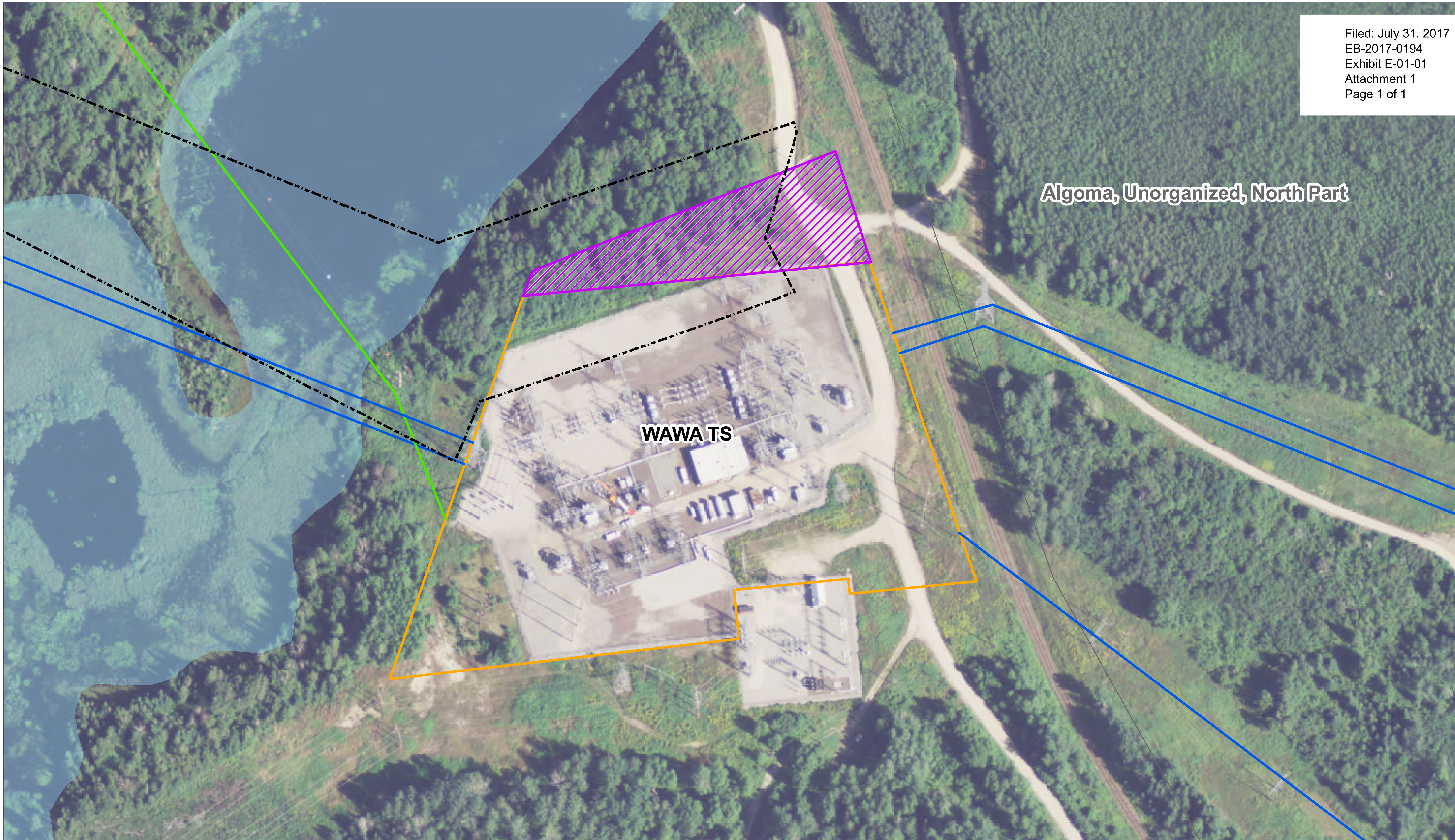
Marathon TS

The current Marathon TS property is approximately 16 acres in size, located on Peninsula Rd north of the Town of Marathon. Planned expansion of Marathon TS will require an additional fee simple land purchase of approximately 12.6 acres to the north east side of the existing property as shown in Attachment 3. The required expansion lands are currently Provincial Crown Lands in the favour of the Ministry of Natural Resources and Forestry ("MNRF"). The additional fee simple property purchase will accommodate all permanent requirements and construction activities to connect the NextBridge line at Marathon TS. An application for a Land Use Permit over the expansion lands has been submitted to the MNRF which will allow for access to the required lands to complete necessary surveying and environmental testing. The fee simple purchase of land will follow the MNRF application process for a Crown Patent and the subject expansion lands will be acquired at Fair Market Value.

Lakehead TS

The current Lakehead TS property is approximately 170 acres in size, located east of Thunder Bay south of Provincial Highway 11/17; see Attachment 4 of this exhibit. The station upgrade requires expanding the station footprint to the west. However, all new permanent infrastructures required for the EWT Station Project will be within Hydro One owned lands. In addition, construction activities will take place within the boundaries of the existing Hydro One owned property. No further permanent rights are required to accommodate the planned station upgrade at Lakehead TS

Temporary construction rights may be required at various locations of the EWT Station Project. Please refer to Attachments 5-7 for a copy of the form of the off-corridor temporary access and temporary access road, construction licence agreement for construction staging, and a damage claim agreement and release forms should they be required in completing this EWT Station Project.



Proposed Wawa TS Expansion

Transmission Line

- 115 kV
- 230 kV
- Proposed Station Expansion Area
- Existing Hydro One Property Boundary
- Proposed NextBridge Transmission Corridor
- Railway
- Waterbody

1:1,500

0 25 50 m

Produced By: Inergi LP, GIS Services
Date: March 14, 2017
Map 17-04_East-West_Tie_Connections_Project_WawaTS_Expansion_GA_ortho

AGREEMENT OF PURCHASE AND SALE

THIS AGREEMENT made and entered into as of this day of 20__.

BETWEEN:

VENDOR NAME

(the **"Vendor"**)
OF THE FIRST PART

AND:

HYDRO ONE NETWORKS INC.

(the **"Purchaser"**)
OF THE SECOND PART

WITNESSETH THAT in consideration of the mutual covenants, agreements and payments herein provided, the parties hereto covenant and agree as follows:

1.0 OFFER

1.1 The Vendor, being the owner of the lands and premises legally described in **Schedule "A"** (the "Lands") hereby agrees to sell to the Purchaser and the Purchaser agrees to purchase from the Vendor, on the terms and conditions set out in this Agreement, a portion of the Lands shown crosshatched and bolded in red on **Schedule "A-1"** attached hereto and being approximately XXX acres (the "Property"), upon and subject to the terms and conditions hereinafter set forth.

1.2 The Vendor acknowledges and understands that upon execution of this Agreement by the Vendor and the Purchaser there shall be a binding agreement of Purchase and Sale between the Purchaser and the Vendor.

1.3 Included in the Purchase Price is the purchase of all of the Vendor's interest in all fixtures, improvements, and appurtenances located on the Property except those listed below which are expressly excluded: NIL

2.0 PURCHASE PRICE

2.1 The purchase price to be paid by the Purchaser to the Vendor for the Property shall be the sum of XXXXXXXXXXXXX ($XXXX.XX) (the **"Purchase Price"**) payable as follows;

(a) **XXXXXXX ($XXXX.XX)** to be submitted by the Purchaser upon the execution of this Agreement by all parties by uncertified cheque payable to the Purchaser's solicitor as a deposit to be held in trust by the Purchaser's solicitor in a non-interest bearing account pending completion or other termination of this Agreement and to be credited on account of the Purchase Price on completion (the **"Deposit"**).

(b) The balance of the Purchase Price by uncertified cheque at the time of closing in accordance with section 3.2 (b) of this Agreement.

2.2 The parties acknowledge that the Purchase Price is based on **$XXXXX per acre for XXX acres** of unimproved lands and the actual area of the Property shall be confirmed by a survey prepared by the Purchaser and Purchase Price shall be adjusted accordingly to the actual acreage.

3.0 CLOSING

3.1 The closing of this transaction shall take place at **2:00pm on the XXth day of XXXXX, 2014** or such earlier time or later time and at such place as shall be agreed in writing by the parties hereto (the **"Closing"**).

3.2 On Closing,

(a) Vacant possession of the Property shall be given to the Purchaser.

(b) Purchaser shall pay the balance of the Purchase Price to the Vendor in accordance with section 2.1 of this Agreement;

(c) Rents, realty taxes, local improvement charges, water and unmetered utility charges and the cost of fuel as applicable shall be apportioned and allowed to the date of completion (the day itself to be apportioned to the Purchaser).

(d) In conformance with subsections 221(2) and 228(4) of the *Excise Tax Act* R.S.C. 1985, c E-15, as amended ("the Act"), Hydro One Networks Inc. shall report and pay to the

Receiver General, the Harmonized Sales Tax (“HST”) applicable to the purchase and sale of the Property. For the purposes of this clause 3.2(d), Hydro One Networks Inc. warrants that it is a HST registrant in good standing under the Act, that its HST registration number is 870865821RT0001, and that it is acquiring the Property for use primarily in the course of its commercial activities.

4.0 REPRESENTATIONS AND WARRANTIES OF VENDOR

4.1 The Purchaser shall be allowed ninety (90) days from the date of this Agreement (the **"Inspection Period"**) to satisfy itself with respect to all matters respecting the Property and the Purchaser’s proposed use of the Property, including but not limited to its present state of repair and condition and any structures thereon, all encumbrances and all regulations and by-laws governing the Property, and the Vendor grants to the Purchaser the right to enter upon the Property and to conduct such inspections, surveys and tests, including but not limited to soil, ground-water, environmental or other inspections, tests, measurements or surveys, as the Purchaser, acting reasonably, deems necessary in this regard, provided the Purchaser takes all reasonable care in the conduct of such inspections, surveys and tests and restores the Property to its prior condition so far as reasonably possible following such inspections and tests. The Vendor assumes no responsibility for and the Purchaser shall indemnify and save harmless the Vendor from and against all claims, demands, costs, damages, expenses and liabilities whatsoever arising out of its presence on the Property or of its activities on or in connection with the Property during the Inspection Period.

4.2 If for any reason, the Purchaser, acting reasonably, is not satisfied with respect to such matters arising from its activities in Section 4.1, it may deliver a notice (the **"Notice of Termination"**) to the Vendor prior to the expiry of the Inspection Period indicating that it is not satisfied with respect to such matters and desires to terminate this Agreement and release the Vendor from any further obligations. Upon delivery by the Purchaser of a Notice of Termination to the Vendor, and this Agreement shall be at an end and the Vendor shall return the Deposit to the Purchaser without deduction and neither Party shall have any further obligation to the other respecting the Agreement.

5.0 TITLE SEARCH PERIOD

5.1 The Purchaser shall be allowed up until ten (10) days prior to closing to investigate title to the Property at its own expense (the **"Title Search Period"**), to satisfy itself that there are no outstanding encumbrances, or liens save and except those listed in Schedule “B” attached hereto and until the earlier of: (i) thirty (30) days from the later of the last date of the title search period or the date or which the conditions in this Agreement are fulfilled or otherwise waived or; (ii) five (5) days prior to completion, to satisfy itself that there are no outstanding work orders or deficiency notices affecting the property. Vendor hereby consents to the Municipality or other governmental agencies releasing to the Purchaser details of all outstanding work orders affecting the Property and the Vendor agrees to execute and deliver such further authorizations in this regard as Purchaser may reasonably require.

5.2 Provided that the title to the Property is good and free from all registered restrictions, charges, liens and encumbrances except those listed in Schedule “B” attached hereto, if within the Title Search Period, any valid objection to title is made by the Purchaser in writing to the Vendor thereof, and which the Vendor shall be unwilling or unable to remove and which the Purchaser will not waive, this Agreement, notwithstanding any intermediate acts or negotiations in respect of such objections, shall be at an end and the Deposit shall be returned to the Purchaser, without deduction, and the Vendor shall not be liable for any costs or damages and the Vendor and the Purchaser shall be released from all obligations hereunder, and the Vendor shall also be released from all obligations under this Agreement, save and except those covenants of the Purchaser expressly stated to survive Closing or other termination of this Agreement. Save as to any valid objection to title made in accordance with this Agreement and within the Title Search Period, and except for any objection going to the root of title, Purchaser shall be conclusively deemed to have accepted Vendor's title to the Property.

5.3 The Vendor and Purchaser agree that there is no condition, express, or implied, representation or warranty of any kind that the future intended use of the Property by the Purchaser is or will be lawful except as may be specifically stipulated elsewhere in this Agreement.

5.4 The Purchaser shall, at its expense, arrange for the preparation of the reference plan for the Property. In the event that the reference plan has not been registered against title to the Property by Closing, then the date for Closing shall be extended.

6.0 REPRESENTATIONS AND WARRANTIES OF PURCHASER

6.1 Purchaser shall, at its own cost, forthwith make such investigation as the Purchaser deems appropriate of the Property and Vendor's title as provided for in this Agreement and shall notify the Vendor of any objection to title, together with a complete copy of any documents and other material information related thereto prior to the expiry of the Inspection Period and Title Search Period.

7.0 INSURANCE

7.1 Until the completion of the sale, all buildings on the property shall be and remain at the risk of the Vendor and the Vendor shall hold all insurance policies and the proceeds thereof in trust for the parties as their interests may appear. In the event of substantial damage, the Purchaser may either (a) terminate this Agreement on written notice to the Vendor, at the earlier of five (5) business days of receiving notification of such damage, or prior to Closing, and the Deposit and accrued interest shall be returned to the Purchaser without deduction; or (b) take the proceeds of any insurance and complete the purchase. No insurance shall be transferred on Closing.

8.0 RESTRICTIONS AND LIMITATIONS

8.1 This Agreement shall be effective to create an interest in the Property only if the applicable subdivision control provisions of the *Planning Act*, R.S.O. 1990, as amended, are complied with by the Vendor prior to Closing. The Vendor shall forthwith make any application to the local Committee of Adjustment or Land Division Committee for any consent that may be required pursuant to the Planning Act. In the event that any such application for consent is denied, or any condition imposed by such body is unacceptable to the Vendor, this Agreement shall be terminated and the Deposit and accrued interest returned to the Purchaser without deduction.

9.0 ADDITIONAL PROVISIONS

9.1 The Transfer/Deed of Land (the **"Transfer"**), save for Land Transfer Tax Affidavits, shall be prepared in registrable form by the Vendor, and the Purchaser covenants at its cost to register the Transfer on Closing. If requested by Purchaser, Vendor covenants that the Transfer Deed to be delivered on completion shall contain the statements contemplated by s. 50(22) of the *Planning Act*, R.S.O. 1990. If requested by Purchaser, the Vendor covenants that the Transfer Deed to be delivered on completion shall contain the statements contemplated by s. 50(22) of the *Planning Act*, R.S.O. 1990.

9.2 Except as otherwise provided herein, each Party shall be responsible to pay its own taxes, legal costs, and the cost of preparation and registration of its own documents

9.3 Time shall in all respects be of the essence hereof provided that the time for doing or completing of any matter provided for herein may be extended or abridged by an agreement in writing signed by the Parties or by their respective solicitors who are specifically authorized in that regard.

9.4 Any tender of documents or money hereunder may be made upon the Parties or their respective solicitors on the Closing day. Money may be tendered by bank draft or uncertified cheque.

9.5 Where this Agreement requires notice to be delivered by one party to the other, such notice shall be given in writing and delivered either personally, or by pre-paid registered post or by facsimile, by the party wishing to give such notice, or by the solicitor acting for such party, to the other party or to the solicitor acting for the other party at the addresses noted below:

To: Vendor Vendor address

To: Vendor's Solicitors
Address

Phone:
Facsimile No.
Attention:

To: Purchaser

Hydro One Networks Inc.
Real Estate Services
1800 Main Street East
Milton, ON
L9T 7S3

Courier: 1800 Main Street East
Milton, Ontario
L9T 2X8

Facsimile No: 905-878-8356
Phone: 905-875-2508 Ext. XXX
Attention: XXXXX

To: Purchaser's Solicitors

Barriston LLP
Att: James McIntosh
P.O. Box 758
Barrie, ON
L4M 4Y5

Phone: 705-725-4903

Such notice shall be deemed to have been given, in the case of personal delivery, on the date of delivery, and, where given by registered post, on the third business day following the posting thereof, and if sent by facsimile, the date of delivery shall be deemed to be the date of transmission if transmission occurs prior to 4:00 p.m. (Toronto time) on a business day and on the business day next following the date of transmission in any other case. It is understood that in the event of a threatened or actual postal disruption in the postal service in the postal area through which such notice must be sent, notice must be given personally as aforesaid or by facsimile, in which case notice shall be deemed to have been given as set out above.

9.6 The Parties acknowledge that there are no covenants, representations, warranties, agreements or conditions, express or implied, collateral or otherwise, forming part of or in any way affecting or relating to this Agreement save as expressly set out in this Agreement and that this Agreement and all Schedules hereto constitute the entire agreement between the parties and may not be modified except as expressly agreed between the Vendor and Purchaser in writing.

9.7 Should any provision or provisions of this agreement be declared illegal or unenforceable, it or they shall be considered separate and severable from the Agreement and its remaining provisions shall remain in force and be binding upon the parties hereto as though the said provision or provisions had never been included.

9.8 No act or omission or delay in exercising any right or enforcing any term, covenant or agreement to be performed under this Agreement shall impair such right or be construed as to be a waiver of any default or acquiescence in such failure to perform, unless such waiver shall be given or acknowledged in writing.

9.9 This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario.

9.10 This Agreement shall constitute the entire Agreement between the Purchaser and Vendor and there is no representation, warranty, collateral agreement or condition affecting this Agreement or the Property or supported hereby other than as expressed herein in writing. This Agreement shall be read with all changes of gender or number required by the context.

9.11 This Agreement and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs, successors, permitted assigns and other legal representatives, as the case may be, of each of the Parties hereto.

9.12 The Vendor warrants that spousal consent is not necessary to this transaction under the provision of the *Family Law Act*, R.S.O. 1990 unless the Vendor's spouse has executed the consent hereinafter provided.

9.13 The Vendor represents that he is not a non-resident for the purposes of section 116 of the *Income Tax Act*, Canada,

9.14 Where each of the Vendor and the Purchaser retain a solicitor to complete this Agreement and where the transaction contemplated herein will be completed by electronic registration pursuant to Part 111 of the Land Registration Reform Act, R.S.O. 1990, and any amendments thereto, the Vendor and the Purchaser acknowledge and agree that the delivery of documents and the release thereof to the Vendor and the Purchaser may, at the solicitor's discretion; (a) not occur contemporaneously with the registration of the Transfer/Deed of Land (and other registrable) documentation), and (b) be subject to conditions whereby the solicitor receiving documents and/or money will be required to hold them in trust and not release them except in accordance with the terms of a written agreement between the solicitors.

9.15 This Agreement and any right or interest transferred hereby may be registered on title to the Property.

9.16 The provisions of the attached Schedules "A", "A-1" and "B" shall form part of this Agreement as if set out herein.

9.17 The Purchaser agrees that it shall be responsible to pay the Vendor's reasonable legal costs up to a maximum of $1,500 which includes all disbursements and Harmonized Sales Tax with respect to this purchase and sale transaction.

IN WITNESS WHEREOF the Parties have hereunto set their respective hands and seals to this Agreement of Purchase and Sale.

Dated this Day of 20 .

SIGNED, SEALED AND DELIVERED
In the presence of) XXXXXXXXXXXXXXXXXXXXXXXX

)
)
)
)
______________________________) __________________________________ (seal)
Print Name of Witness Name:
Title:

SIGNED, SEALED AND DELIVERED
In the presence of) XXXXXXXXXXXXXXXXXXXXXXXX
)
)
)
)
______________________________) __________________________________ (seal)
Print Name of Witness Name:
Title:

HYDRO ONE NETWORKS INC.

Per: ________________________________
Lou Fortini
Title: Director of Real Estate

I have authority to bind the Corporation

SCHEDULE “A”

LEGAL DESCRIPTION OF LANDS

SCHEDULE "A-1"

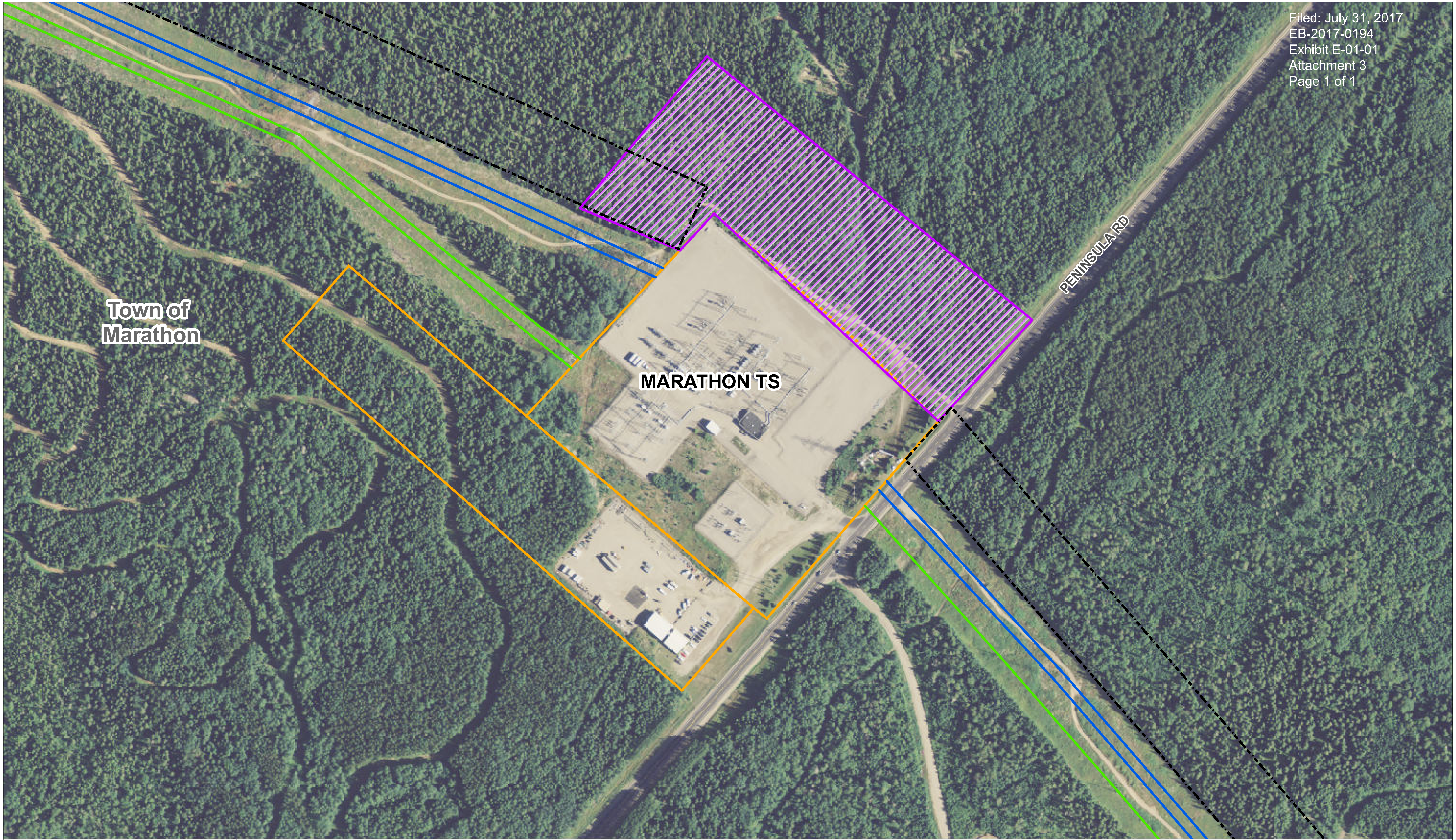
SKETCH OF PROPERTY

PLAN 00R-0000

SCHEDULE "B"

List of Permitted Encumbrances

NIL



Proposed Marathon TS Expansion

Transmission Line

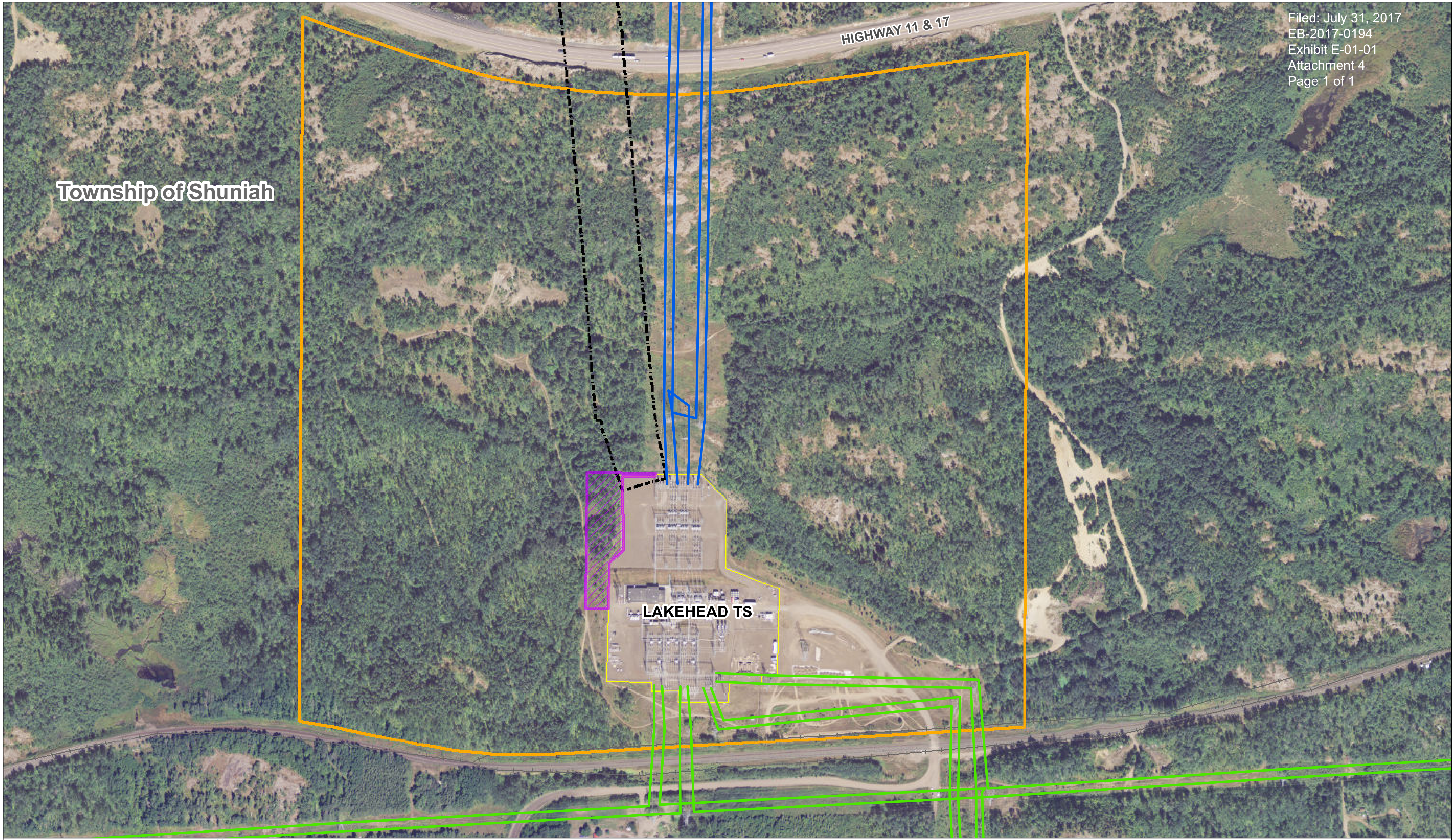
- 115 kV
- 230 kV

- Proposed Station Expansion Area
- Existing Hydro One Property Boundary
- Proposed NextBridge Transmission Corridor

1:3,000

0 50 100 m

Produced By: Inergi LP, GIS Services
Date: March 14, 2017
Map 17-04_East-West_Tie_Connections_Project_MarathonTS_Expansion_GA_ortho



Proposed Lakehead TS Expansion

Transmission Line

- 115 kV
- 230 kV
- Proposed Station Expansion Area
- Existing Hydro One Property Boundary
- Existing Fence Line
- Proposed NextBridge Transmission Corridor
- Railway

1:4,000

0 75 150 m

Produced By: Inergi LP, GIS Services
Date: March 28, 2017
Map 17-04_East-West_Tie_Connections_Project_LakeheadTS_Expansion_GA_ortho

Temporary Access and Temporary Access Road

THIS AGREEMENT made in duplicate the **___________**day of **___________**___20XX

Between:

INSERT NAME OF OWNER

(hereinafter referred to as the "Grantor")

OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to "HONI")

OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as, ***INSERT LEGAL DESCRIPTION*** (the "Lands").

WHEREAS HONI in connection with its **[Insert Project Name]** Project (the "Project") desires the right to enter onto the Lands in order to construct temporary access roads on, over and upon the Lands in order to access the construction site associated with the "Project.

WHEREAS the Grantor is agreeable in allowing HONI to enter onto the Lands for the purpose of constructing temporary access roads on, over and upon the Lands, subject to the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the sum of ***INSERT CONSIDERATION*** to be paid by HONI to the Grantor, and the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. The Grantor hereby grants, conveys and transfers to HONI in, over, along and upon that part of the Lands highlighted in yellow as shown in Schedule "A" attached hereto (the "Access Lands"), the rights privileges, and easements as follows:

(a) for the servants, agents, contractors and workmen of HONI at all times with all necessary vehicles and equipment to pass and repass over the Access Lands for the purpose of access to the construction site associated with the Project, subject to payment of compensation for damages to any crops caused thereby;

(b) to construct, use and maintain upon the Access Lands, a temporary road to the construction site associated with the Project, together with such gates, bridges and drainage works as may be necessary for HONI's purposes (collectively, the "Works"), all of which Works shall be removed by HONI upon completion of the construction associated with the Project.; and

(c) to cut and remove all trees, brush and other obstructions made necessary by the exercise of the rights granted hereunder

2. The term of this Agreement and the permission granted herein shall be XXXX from the date written above (the "Term"). HONI may, in its sole discretion, and upon 60 days notice to the Grantor, extend the Term for an additional length of time, which shall be negotiated between the parties.

3. Upon the expiry of the Term or any extension thereof, HONI shall repair any physical damage to the Access Lands and/or Lands resulting from HONI's use of the Access Lands and the permission granted herein; and, shall restore the Access Lands to its original condition so far as possible and practicable.

4. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Access Lands shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

5. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Access Lands or of its activities on or in connection with the Access Lands arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

6. Notices to be given to either party shall be in writing, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

TO HONI:

Hydro One Networks Inc.
Real Estate Services
5th Floor
483 Bay Street South Tower
Toronto, Ontario M5G 2P5

Attention:
Fax:

TO GRANTOR:

7. Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5th) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

8. Any amendments, modifications or supplements to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

9. The burden and benefit of this Agreement shall run with the Lands and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs; successors, permitted assigns and other legal representatives, as the case may be, or each of the Parties hereto.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

SIGNED, SEALED & DELIVERED In the presence of:	**OWNER:**
Witness	
Witness	

HYDRO ONE
HST #

HYDRO ONE NETWORKS INC.

By:

Name:
Title:

I have authority to bind the Corporation

SCHEDULE "A"

PROPERTY SKETCH

TEMPORARY CONSTRUCTION LICENCE

THIS AGREEMENT made in duplicate the X day of X 20XX

BETWEEN:

HYDRO ONE NETWORKS INC. (hereinafter called the "HONI") OF THE FIRST PART

and

XXXXX (hereinafter called the "Owner") OF THE SECOND PART

WHEREAS:

(a) The Owner is the registered owner of lands legally described as ***INSERT LEGAL DESCRIPTION*** (the "Lands").

(b) HONI will be constructing new electrical transmission facilities in the area highlighted in yellow on a portion of the Lands more particularly shown on Schedule "A" attached hereto (the "Project") and requires a portion of the Lands as a temporary construction area.

(c) The Owner is agreeable in allowing HONI to enter onto the Lands and using a portion of the Lands for the purposes of a temporary construction area, which area is more particularly shown in red on Schedule "A" attached hereto in order to facilitate construction work on HONI's adjacent transmission corridor.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT IN CONSIDERATION of the sum of Five Dollars ($5.00) now paid by each party to the other and the respective covenants and agreements of the parties hereinafter contained (the receipt and sufficiency of which are hereby acknowledged by the parties hereto), the parties hereto agree as follows:

1. The Owner hereby grants to HONI the right to enter upon a portion of the Lands highlighted in red, being XX acres, for the purpose of a temporary construction area (the "Licenced Area").

2. HONI will pay the Owner the amount of ***INSERT CONSIDERATION*** for the rights granted herein (the "Licence Fee").

3. HONI agrees that it shall take all reasonable care in its construction practices. HONI agrees that it shall erect such barriers and take such other appropriate safety precautions (i.e. gating system), as may be reasonably required to effectively prevent death or injuries to persons or the Owner's property during the Term of this Agreement.

4. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Licenced Area shall be at the sole risk of HONI and the Owner shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Owner.

5. HONI agrees that it shall indemnify and save harmless the Owner from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Lands or of its activities on or in connection with the Licenced Area arising out of the permission granted herein except to the extent any of such Costs arise out of the negligence or willful misconduct of the Owner.

6. This Agreement and the permission granted herein shall be for a XXXXX term commencing from XXXXX until XXXXX (the "Term").

7. This Agreement and the permission granted herein may be renewed by HONI on a month to month basis up to an additional one year term, upon the same terms and conditions contained herein, including the Licence Fee, which amount shall be pro-rated to a monthly amount if applicable, save and except any further right to renewal. In the event HONI desires to renew this Licence, it shall provide notice in writing to the Owner of its desire to renew the Licence, at least thirty (30) days prior to the end of the Term, or any renewal thereof.

8. Upon the expiry of this Licence, HONI shall remove all equipment and debris from the Licenced Area and shall restore the Licenced Areas to as close as is practicable to its original condition immediately prior to HONI's occupancy at HONI's sole cost and expense.

9. Any notice to be given to the Owner shall be in writing and shall be delivered by pre-paid registered post or by facsimile, at the address noted below:

   in the case of the Owner, to:

   Attention:
   Fax No.:

   in the case of the HONI, to:

   Attention:
   Fax No.:

   Such notice shall be deemed to have been given, in, writing or delivered, on the date of delivery, and, where given by registered post, on the third business day following the posting thereof, and if sent by facsimile, the date of delivery shall be deemed to be the date of transmission if transmission occurs prior to 4:00 p.m. (Toronto time) on a business day and on the business day next following the date of transmission in any other case. It is understood that in the event of a threatened or actual postal disruption in the postal service in the postal area through which such notice must be sent, notice must be given in writing by delivery or by facsimile, in which case notice shall be deemed to have been given as set out above. “Business day” shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario.

10. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

11. The burden and benefit of this Agreement shall run with the Lands and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs; successors, permitted assigns and other legal representatives, as the case may be, or each of the Parties hereto.

12. Any amendments, modification or supplement to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with same degree of formality as the execution of this Agreement.

IN WITNESS WHEREOF the parties hereto have executed this Agreement by the hands of their duly authorized signing officers in that regard.

Per: ______________________________

Name:

Title:

I have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

Per: ______________________________

Name:

Title:

I have authority to bind the Corporation

SCHEDULE "A"

Damage Claim

THIS MEMORANDUM OF AGREEMENT dated the day of 20XX

Between:

herein called the “Claimant”

-and-

Hydro One Networks Inc.

herein called “HONI”

Witnesseth:

The Claimant agrees to accept ………………………………………………………………($) in full payment and satisfaction of all claims or demands for damages of whatsoever kind, nature or extent which may have been done to date by HONI during the construction, completion, operation or maintenance of the works of HONI constructed on Lot(s) ………………………………….. , Concession(s) ……………………………….. or according to Registered Plan No. ………………… in the …………………………………………………… of ……………………………………………… of which property the Claimant is the ………………………………… and which damages may be approximately summarized and itemized as:

WITNESS

Name:

Address:

CLAIMANT

Name:

Address:

HYDRO ONE NETWORKS INC.

HYDRO ONE
HST#

Per:

Name:
Title:

I have authority to bind the Corporation

RELEASE AND WAIVER

FULL AND FINAL RELEASE

IN CONSIDERATION of the payment or of the promise of payment to the undersigned of the aggregate sum of [INSERT SETTLEMENT AMOUNT] ($), the receipt and sufficiency of which is hereby acknowledged, I/We, the undersigned, on behalf of myself/ourselves, my/our heirs, executors, administrators, successors and assigns (hereinafter the "Releasors"), hereby release and forever discharge HYDRO ONE NETWORKS INC., its officers, directors, employees, servants and agents and its parent, affiliates, subsidiaries, successors and assigns (hereinafter the "Releasees") from any and all actions, causes of action, claims and demands of every kind including damages, costs, interest and loss or injury of every nature and kind, howsoever arising, which the Releasors now have, may have had or may hereafter have arising from or in any way related to [INSERT DESCRIPTION OF THE DAMAGE CAUSED] on lands owned by [INSERT PROPERTY OWNER NAME] and specifically including all damages, loss and injury not now known or anticipated but which may arise or develop in the future, including all of the effects and consequences thereof.

AND FOR THE SAID CONSIDERATION, the Releasors further agree not to make any claim or take any proceedings against any other person or corporation who might claim contribution or indemnity under the provisions of the *Negligence Act* and the amendments thereto from the persons or corporations discharged by this release.

AND FOR THE SAID CONSIDERATION, the Releasors further agree not to disclose, publish or communicate by any means, directly or indirectly, the terms, conditions and details of this settlement to or with any persons other than immediate family and legal counsel.

AND THE RELEASORS hereby confirm and acknowledge that the Releasors have sought or declined to seek independent legal advice before signing this Release, that the terms of this Release are fully understood, and that the said amounts and benefits are being accepted voluntarily, and not under duress, and in full and final compromise, adjustment and settlement of all claims against the Releasees.

IT IS UNDERSTOOD AND AGREED that the said payment or promise of payment is deemed to be no admission whatsoever of liability on the part of the Releasees.

AND IT IS UNDERSTOOD AND AGREED that this Release may be executed in separate counterparts (and may be transmitted by facsimile) each of which shall be deemed to be an original and that such counterparts shall together constitute one and the same instrument, notwithstanding the date of actual execution.

IN WITNESS WHEREOF, the Releasors have hereunto set their respective hands this .... day of ...., 20XX.

SIGNED, SEALED & DELIVERED In the presence of:	
Witness	Name

SIGNED, SEALED & DELIVERED In the presence of:	
Witness	Name

System Impact Assessment

Please refer to Attachment 1 for the Final System Impact Assessment ("SIA") prepared by the Independent Electricity System Operator for the EWT Station Project. The SIA confirms that the Project will have no material adverse impact on the reliability of the integrated power system and that the project modification are expected to be adequate for the targeted westward transfer level of 450 MW across the East-West Tie.

Attachment 2 is an Addendum to a previous SIA for the EWT Project focusing on the EWT Line Project, filed under EB-2017-0182 by NextBridge.

REPORT

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final SIA Report

CAA ID: 2016-568
Project: Ontario 230 kV East-West Tie Connections
Applicant: Hydro One Networks Inc.

Connections & Registration Department
Independent Electricity System Operator

Date: December 22, 2016

Document Name	System Impact Assessment Report
Issue	Final SIA Report
Reason for Issue	Request for connection assessment
Effective Date	December 22, 2016

System Impact Assessment Report

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, Section 6 of the Market Rules.

Conditional approval of the proposed connection is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, Section 6 of the Market Rules. This report does not in any way constitute an endorsement, agreement, consent or acknowledgment of any kind of the proposed connection for the purposes of obtaining or administering a contract with the IESO for the procurement of electricity supply, generation, demand response, conservation and demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, Section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of this transmission system reinforcement proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a system impact assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Executive Summary

Project Description

The Ontario 230 kV East-West Tie (the "East-West Tie") consists of the 230 kV transmission circuits from Wawa TS to Marathon TS to Lakehead TS. Upper Canada Transmission Inc. (the "transmitter") is proposing to reinforce the East-West Tie (under CAA-ID 2014-514 – Addendum to the final SIA report) by adding new 230 kV circuits: M37L and M38L from Lakehead TS to Marathon TS, and W35M and W36M from Marathon TS to Wawa TS. Hydro One Networks Inc. (the "connection applicant") is proposing to modify their three terminal transformer stations: Lakehead TS, Marathon TS and Wawa TS (the "project") to accommodate the new 230 kV transmission circuits, as follows:

a. Terminal transformer station work:
   - Reconfiguration of 230 kV buses and diameters at the three terminal transformer stations;
   - Installation of new 230 kV circuit breakers and disconnect switches;
   - Termination of the new 230 kV circuits M37L, M38L, W35M and W36M at their respective terminal transformer stations;
   - Re-termination of the existing 230 kV transmission circuits M23L, M24L, W21M, W22M and W23K at their respective terminal transformer stations;
   - Installation of two 230 kV shunt reactors at Marathon TS;
   - Installation of a 230 kV shunt reactor at Lakehead TS;
   - Installation of a 230 kV shunt capacitor bank at Lakehead TS;
   - Revision of the Remedial Action Scheme (RAS) named Northwest Special Protection Scheme #2 (NW SPS 2) to include the new contingency conditions arising from the reconfiguration of the 230 kV buses at the terminal transformer stations; and
   - Changes to the protection, control and telecommunications facilities for the reconfiguration of the buses at the three terminal transformer stations.

b. Line work:
   - Installation of connections between the last structure of the transmitter's new 230 kV circuits outside the three terminal transformer stations and the termination points for these circuits within the terminal transformer stations; and

This System Impact Assessment (SIA) confirms that the project is adequate for the targeted westward transfer level of 450 MW across the East-West Tie.

The proposed in-service date of the project is December 15, 2020.

Notification of Conditional Approval

The project will not have a material adverse impact on the reliability of the integrated power system. It is therefore recommended that a *Notification of Conditional Approval for Connection* be issued for the project subject to the requirements listed in this report.

Findings

The SIA results confirmed the following:

1. The project will not have a materially adverse impact on the reliability of the integrated power system. The proposed modifications are expected to be adequate for the targeted westward transfer level of 450 MW across the East-West Tie;
2. The modifications of the terminal transformer stations, additional upgrades, equipment and reactive support, as proposed by the connection applicant, are acceptable to the IESO;
3. The proposed reactive control devices are appropriate to control voltages within applicable ranges under all foreseeable conditions. Since the voltages near the project are strongly dependent on the flows across the tie and because the flows across the tie can vary over a wide range throughout the day, these reactive control devices may need to be switched multiple times a day;
4. The existing parallel 115 kV circuits A5A, A1B and T1M between Alexander SS and Marathon TS are adequate for a westward transfer capability of the East-West Tie of 450 MW;
5. Under the new North American Electric Reliability Corporation's (NERC) definition of the Bulk Electric System (BES) all the 230 kV transmission equipment installed for this project will be categorized as BES elements; and
6. At the westward transfer levels of about 450 MW studied in this report, the project's equipment will not fall within the Northeast Power Coordinating Council (NPCC) definition of the Bulk Power System (BPS). As the final SIA report under CAA_ID 2014-514 indicated, the original assessment showed that once the future Static Var Compensator (SVC) is installed at Marathon TS and the East-West Tie westward transfer can be increased to about 650 MW, Marathon TS, together with all of the 230 kV circuits that terminate at that station (existing: M23L, M24L, W21M and W22M, and new: M37L, M38L, W35M and W36M) will fall within the NPCC's BPS definition. Additional tests will be required, once the model for the Marathon SVC becomes available, to determine the future status of Lakehead TS, Wawa TS, Mississagi TS and their associated 230kV circuits.

Connection Requirements

1. To avoid any possible conflict between the operation of the proposed NW SPS 2 and the local voltage based capacitor and reactor switching schemes, the connection applicant must initiate, at the appropriate time during the development of the project, a review of the voltage settings of all the local schemes by the IESO, participate as the equipment owner in the review and implement the new settings, once agreed upon, in a timely manner.
2. The connection applicant shall satisfy all general requirements listed in section 2 of this report.

Recommendation

When the existing synchronous condenser at Lakehead TS is determined to be at 'end-of-life' it is recommended that consideration be given to replacing it with an SVC that has a rating of at least ± 100 Mvar.

– End of Section –

1. Project Description

1.1 Introduction

The Ontario 230 kV East-West Tie (the "East-West Tie") consists of the 230 kV transmission circuits from Wawa TS to Marathon TS to Lakehead TS. Upper Canada Transmission Inc. (the "transmitter") is proposing to reinforce the East-West Tie (under CAA-ID 2014-514 – Addendum to the final SIA report) by adding new 230 kV circuits: M37L and M38L from Lakehead TS to Marathon TS, and W35M and W36M from Marathon TS to Wawa TS. Hydro One Networks Inc. (the "connection applicant") is proposing to modify their three terminal transformer stations: Lakehead TS, Marathon TS and Wawa TS (the "project") to accommodate the new 230 kV transmission circuits, as follows:

a. Terminal transformer station work:
   - Reconfiguration of 230 kV buses and diameters at the three terminal transformer stations;
   - Installation of new 230 kV circuit breakers and disconnect switches;
   - Termination of the new 230 kV circuits M37L, M38L, W35M and W36M at their respective terminal transformer stations;
   - Re-termination of the existing 230 kV transmission circuits M23L, M24L, W21M, W22M and W23K at their respective terminal transformer stations;
   - Installation of two 230 kV shunt reactors at Marathon TS;
   - Installation of a 230 kV shunt reactor at Lakehead TS;
   - Installation of a 230 kV shunt capacitor bank at Lakehead TS;
   - Revision of the Remedial Action Scheme (RAS) named Northwest Special Protection Scheme #2 (NW SPS 2) to include the new contingency conditions arising from the reconfiguration of the 230 kV buses at the terminal transformer stations; and
   - Changes to the protection, control and telecommunications facilities for the reconfiguration of the buses at the three terminal transformer stations.

b. Line work:
   - Installation of connections between the last structure of the transmitter's new 230 kV circuits outside the three terminal transformer stations and the termination points for these circuits within the terminal transformer stations; and

The project schedule was revised[1] in 2015 and the current proposed in-service date is the end of 2020.

In this revision, the IESO has recommended changes to the connection facilities, including the addition of 230 kV shunt reactors and the postponing of the originally proposed SVC at Marathon TS to a future date when there is a need to increase the westward transfer capability of the East-West Tie to 650 MW. Following this IESO recommendation, the connection applicant indicated that upgrading sections of the 115 kV circuits A5A, A1B and T1M between Alexander SS and Marathon TS for a continuous summer rating of 500 A (about 100 MVA) could be postponed until a future date when there is a need for this upgrade (i.e. a westward transfer capability of 650 MW is required for the East-West Tie).

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[1] Available on Ontario Energy Board's website at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2011-0140&sortd1=rs_dateregistered&rows=200

The project is expected to be adequate for the targeted transfer of 450 MW westwards across the East-West Tie.

1.2 Station Arrangement of Connection Facilities

The connection applicant proposes to complete the following work at the three terminal transformer stations: Lakehead TS, Marathon TS and Wawa TS to achieve a targeted transfer of 450 MW westwards across the East-West Tie:

Lakehead TS:

- Add a new 230 kV diameter and 5 new 230 kV breakers, with associated breaker disconnect switches;
- Terminate the new 230 kV transmission circuits M37L and M38L on the diameters through line disconnect and ground switches;
- Replace the existing disconnect/ground combination switches of circuits M23L and M24L;
- Add a new 230 kV shunt reactor with its switching breaker/switcher, disconnect switch and their associated facilities; and
- Add a new 230 kV shunt capacitor bank with its series reactor, switching breakers, disconnect switch and their associated facilities.

The following figure shows the proposed configuration at Lakehead TS:

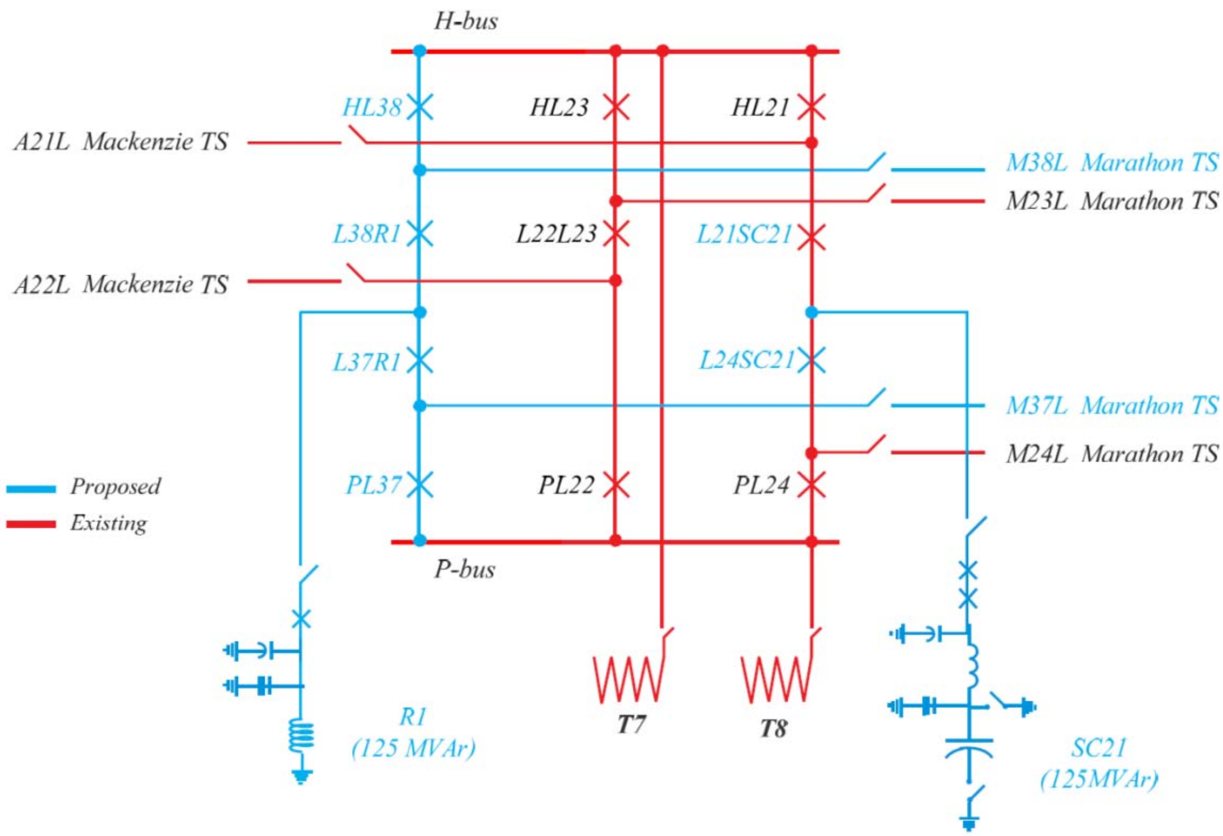

Figure 1: Lakehead TS – proposed station configuration

Marathon TS:

- Convert the existing 4-breaker 230 kV ring bus to a 2-bus, 4-diameter, 14-breaker arrangement, with associated breaker disconnect switches;
- Terminate the new 230 kV transmission circuits M37L, M38L, W35M and W36M on the diameters through line disconnect and ground switches;
- Re-terminate the existing circuits M23L and W21M and replace the existing disconnect/ground combination switches of circuits M23L, M24L, W21M and W22M; and
- Add two new 230 kV shunt reactors and their switching breakers/switchers; disconnect switches and their associated facilities.

The following figure shows the proposed configuration at Marathon TS:

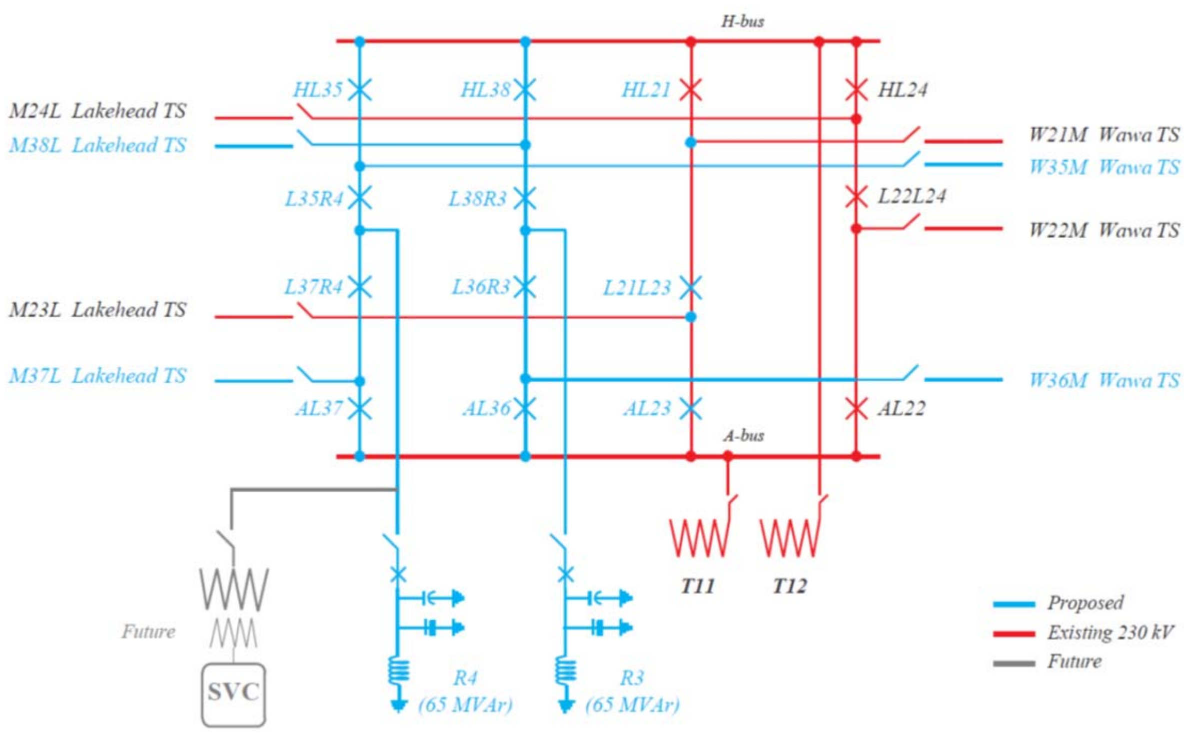

Figure 2: Marathon TS - proposed station configuration

Wawa TS:

- Convert the existing 5-breaker 230 kV ring bus to a 2-bus, 4-diameter, 11-breaker arrangement, with associated breaker disconnect switches;
- Terminate the new 230 kV transmission circuits W35M and W36M on the diameters through line disconnect and ground switches; and
- Re-terminate the existing circuits W21M and W23K, motorize the existing ground switch of circuit W23K (which becomes the new switch for circuit W21M), and replace the existing disconnect/ground combination switches of circuit W22M.

The following figure shows the proposed configuration at Wawa TS:

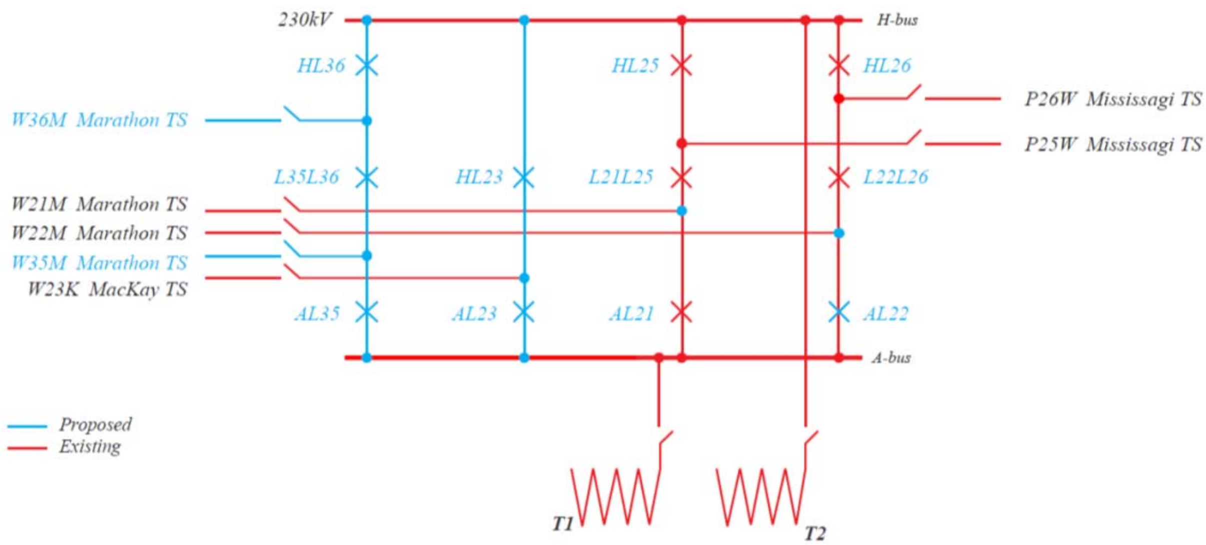

Figure 3: Wawa TS – proposed station configuration

Details of the proposed equipment to be installed in these terminal stations are presented in Section 3 (Models and Data) of this report.

<u>Line Work</u>

Circuit Terminations

- Connect the new 230 kV transmission circuits M37L, M38L, W35M and W36M from their last structure outside Lakehead TS, Marathon TS and Wawa TS to the 230 kV line termination structures in these stations. The new circuits are proposed to have single 1192.5 kcmil conductors with the long-term rating of 1440 A;
- Terminate the skywires of these new transmission circuits at the three terminal stations (one of the skywires between Wawa TS and Marathon TS and between Marathon TS and Lakehead TS is expected to be OPGW); and
- Re-terminate the existing circuits at the three terminal station on the station diameters, as applicable.

The modifications proposed by the connection applicant for the three terminal transformer stations and the additional upgrades will eliminate breaker-failure conditions that can impose restrictions on the current operation of the East-West Tie and are therefore acceptable to the IESO.

– End of Section –

2. General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and Reliability Standards. The following sections highlight some of the general requirements that are applicable to the project.

2.1 Reliability Standards

Under the North-American Electric Reliability Corporation's (NERC) Bulk Electric system (BES) definition, all 230 kV elements of this project will be classified as BES.

The connection applicant will need to ensure that the project complies with the applicable NERC reliability standards. To determine the standard requirements that are applicable to this project, the IESO provides a mapping tool titled "NERC Reliability Standard Mapping Tool/Spreadsheet," which can be accessed at the IESO's public website:

http://ieso.ca/imoweb/pubs/ircp/NERC_Reliability_Standards_Mapping_Tool_Spreadsheet.xls.

Note, the connection applicant and/or the transmitter may request an exemption to the application of the BES definition. The procedure for submitting an application for exemption can be found in Market Manual 11.4: "Ontario Bulk Electric System (BES) Exception" at the IESO's website:

http://ieso.ca/imoweb/pubs/ircp/rc_OntarioBESException.pdf

At the westward transfer levels of about 450 MW studied in this report, the project's equipment will not fall within the Northeast Power Coordinating Council (NPCC) definition of the Bulk Power System (BPS).As presented in the final SIA report for the transmitter's project (CAA_ID 2014-514), it is expected that once the new SVC is installed at Marathon TS and the East-West Tie transfer capability is increased to 650 MW westward, Marathon TS, together with all of the 230 kV circuits that terminate at that station (existing: M23L, M24L, W21M and W22M, and new: M37L, M38L, W35M and W36M) will fall within the NPCC's definition of the BPS.

Additional assessments will be required, once the model for the future Marathon SVC becomes available, to determine if Lakehead TS, Wawa TS and Mississagi TS and their associated 230 kV circuits will also be classified as BPS.

However, the IESO recommends that any new facilities that the connection applicant is planning to install under this project should be suitable for their future designation to ensure that they remain compliant with the applicable NPCC criteria. To determine the standard requirements that are applicable to this project, the IESO provides a mapping tool titled "NPCC Criteria Mapping Spreadsheet," which can be accessed at the IESO's public website: http://ieso.ca/imoweb/pubs/ircp/NPCC%20Criteria_Mapping_Spreadsheet.xls.

The IESO's criteria for determining applicability of NERC reliability standards and NPCC Criteria can be found in the Market Manual 11.1: "Applicability Criteria for Compliance with NERC Reliability Standards and NPCC Criteria" at the IESO's website http://ieso.ca/imoweb/pubs/ircp/IESO_Applicability_Criteria_for_Compliance_with_NERC_Standards_and_NPCC_Criteria.pdf

Compliance with these reliability standards will be monitored and assessed as part of the IESO's Ontario Reliability Compliance Program. For more details about compliance with applicable reliability standards reliability standards, the connection applicant is encouraged to contact orcp@ieso.ca and also visit the following webpage: http://www.ieso.ca/imoweb/ircp/orcp.asp.

Note, the BPS and BES classifications of the IESO-controlled grid will be re-evaluated by the IESO on an annual basis. As the electrical system evolves, any existing BPS or BES classification may change.

2.2 Voltage Levels

The connection applicant shall ensure that the project's equipment meets the voltage requirements specified in Section 4.2 and Section 4.3 of the Ontario Resource Transmission Assessment Criteria (ORTAC).

2.3 Fault Levels

The Transmission System Code requires the new equipment to be designed to withstand the fault levels in the area where the equipment is installed. Thus, the connection applicant shall ensure that all new equipment installed for the project is designed to withstand the fault levels in the area. If any future system changes result in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in the Transmission System Code. Appendix 2 of the Transmission System Code establishes the maximum fault levels for the transmission system. For the 230 kV system, the maximum 3 phase symmetrical fault level is 63 kA and the maximum single line to ground symmetrical fault level is 80 kA (usually limited to 63 kA).

Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 230 kV breakers must be ≤ 3 cycles. Thus, the connection applicant shall ensure that the installed breakers meet the required interrupting time specified in the Transmission System Code. Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 250 kV.

2.4 Protection Systems

The connection applicant shall ensure that the protection systems installed at the project are designed to satisfy all the requirements of OEB's Transmission System Code (TSC). New protection systems must be coordinated with the existing protection systems.

The protection systems installed for the project must only trip the appropriate equipment required to isolate the fault. After the project begins commercial operation, if an improper trip of the 230 kV circuits occurs due to events within the project, the project (or its deficient part) may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

The project shall have the capability to ride through routine switching events and design criteria contingencies in the grid that do not disconnect the project by configuration. Standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times are to be assumed.

Remedial Action Schemes (RAS) can be operated more efficiently if they have features to allow their arming and disarming directly by the IESO operators. The connection applicant must therefore work with the IESO to install facilities that allow arming and disarming of the NW SPS 2 directly from the IESO control room.

Protection modifications that are different from those considered in this SIA must be submitted by the connection applicant to the IESO at least six (6) months before any modifications are to be implemented. If those modifications result in adverse reliability impacts, mitigation solutions must be developed.

The connection applicant must provide during the IESO Market Registration process the actual protection operating times, in accordance with Market Manual 2: Market Administration, Part 2.20: Performance Validation (Sections 4.8 and 4.9).

2.5 Connection Equipment

The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient temperature conditions. The connection applicant must also ensure that connection equipment is designed such that the adverse effects of its failure on the IESO-controlled grid are mitigated.

2.6 Disturbance Recording

The connection applicant is required to extend the coverage of the existing disturbance recording devices at the terminal transformer stations: Lakehead TS, Marathon TS and Wawa TS, to cover the new 230 kV transmission circuits: M37L, M38L, W35M and W36M. These modifications are required to meet the technical specifications provided by the IESO during the Market Registration process. The devices will be used to monitor and record electric quantities on the system in order to verify the dynamic response of generators. The quantities to be recorded and the trigger settings will be provided by the IESO during the IESO Market Registration process.

2.7 Telemetry

According to Section 7.3 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.15 of the Market Rules on a continual basis. The whole telemetry list will be finalized during the IESO Market Registration process and is expected to be similar to the existing East-West Tie's transmission circuits. At a minimum, the same quantities and statuses that are provided for existing equipment and lines at the three stations must also be provided for the new equipment and lines that are installed for the project.

The data shall be provided with equipment that meets the requirements set forth in Appendix 2.2, Chapter 2 of the Market Rules and Section 5.3 of Market Manual 1.2, in accordance with the performance standards set forth in Appendix 4.19 subject to Section 7.6A of Chapter 4 of the Market Rules.

As part of the IESO Market Registration process, the connection applicant must complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO final approval to connect any phase of the project is granted.

2.8 Power System Restoration

The connection applicant is already a restoration participant. Details regarding restoration participant requirements will be finalized during the IESO Market Registration process.

2.9 IESO Market Registration Process

The connection applicant must initiate and complete the IESO Market Registration process in a timely manner, at least seven months before energization to the IESO-controlled grid and prior to the commencement of any project related outages, in order to obtain IESO final approval for connection.

"As-built" equipment data and any controls, including any applicable models and data that would be operational, must be provided to the IESO. This includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Market Rules, NPCC and NERC rules. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages.

As part of the IESO Market Registration process, the connection applicant must provide evidence to the IESO, as required under Market Manual 2: Market Administration, Part 2.20: Performance Validation (Sections 2, 4 and 5.4), confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Market Registration process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

At the sole discretion of the IESO, performance tests may be required at transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

2.10 Project Status

As per Market Manual 2.10, the connection application will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO. The project status report form can be found on the IESO web site at http://www.ieso.ca/imoweb/pubs/caa/caa_f1399_StatusReport.doc. Failure to comply with project status requirements listed in Market Manual 2.10 will result in the project being withdrawn.

The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Market Manual 2.10. A committed project is a project that has demonstrated to the IESO a high probability of being placed into service.

This project will be deemed committed by the IESO when the connection applicant, as a licensed transmitter, identifies the project in their Plans for New or Modified Facilities Information Submittal Form for 18-Month Outlook (IESO_FORM_1484), or Plans for Retired, New or Modified Facilities Information Submittal Form (IESO_FORM_1494) provided to the IESO as part of its submission for the IESO 18-Month Outlook and other reliability assessments.

– End of Section –

3. Models and Data

3.1 Parameters of the Proposed Equipment

The connection applicant submitted the following information:

Table 1: Proposed minimum current ratings of bus work:

Station	Minimum current rating (A)			
	Main buses	Existing Diameters	New Diameters	New Line Exits
Wawa TS	3000	2000	3000	1600
Marathon TS	3000	2000	3000	1600
Lakehead TS	3000	2000	3000	1600

Table 2: 230 kV circuit breakers

Breaker type	SF6,Three-phase Ganged-pole
Interrupting medium	SF6
Rated maximum continuous voltage	250 kV (minimum)
Rated maximum voltage for up to 30 minutes without interrupting fault current during this period.	263 kV (minimum)
Rated interrupting current	40 kA symmetrical (minimum)
Rated continuous current	3000 A (minimum)
Rated interrupting time	3 cycles (maximum)

Table 3: 230 kV reactor switching breaker/switcher

Type	SF6, Three-phase Breaker or Reactor Switcher
Interrupting medium	SF6
Rated maximum continuous voltage	250 kV (minimum)
Rated maximum voltage for up to 30 minutes (must be able to close the reactor at this voltage but doesn't open or interrupt fault currents at this voltage)	263 kV (minimum)
Rated fault current (without interrupting*)	30 kA symmetrical (minimum)
Rated continuous current	1000 A (minimum)

* Fault currents will be interrupted by the diameter breakers and not by the reactor breaker/switcher.

Table 4: Primary SC21 capacitor bank switching breaker

Breaker type	Definite purpose and independent pole operated (IPO) for capacitor switching, equipped with provision for synchronized closing
Interrupting medium	SF6
Rated maximum voltage	250 kV (minimum)
Rated maximum voltage for up to 30 minutes without interrupting fault current (may be opened or closed during this period if there is no fault)	263 kV (minimum)
Rated interrupting current	30 kA symmetrical (minimum)
Rated continuous current	2000 A
Rated Interrupting Time	3 cycles (maximum)

Table 5: Backup SC21 capacitor bank switching breaker

Breaker type	Definite purpose CB with rated capacitance switching currents as per ANSI C37-06-2000 SF6: ganged-pole (if a ganged-pole that meets the 620 kV TRV requirement is not available an IPO breaker is acceptable)
Interrupting medium	SF6
Rated maximum voltage	250 kV (minimum)
Rated maximum voltage for up to 30 minutes without interrupting fault current (may be opened or closed during this period if there is no fault)	263 kV (minimum)
Rated interrupting current	30 kA symmetrical (minimum)
Rated continuous current	2000 A
Rated Interrupting Time	3 cycles (maximum)

Table 6: 230 kV Line disconnect switches

Continuous current	2000 A rms (minimum)
Operating voltage	230 kV rms (nominal), 250 kV (maximum continuous)
Short circuit withstand capability	30 kA rms symmetrical (minimum)

Table 7: 230 kV Breaker disconnect switches

Continuous current	3000 A rms (minimum)
Operating voltage	230 kV rms (nominal), 250 kV (maximum continuous)
Short circuit withstand capability	30 kA rms symmetrical (minimum)

Table 8: 230 kV reactor disconnect switches

Continuous current	1000 A (minimum)
Operating voltage	230 kV (nominal) 250 kV (maximum continuous)
Short circuit withstand capability	30 kA symmetrical (minimum)

Table 9: 230 kV capacitor bank disconnect switch:

Continuous current	1000 A (minimum)
Rated voltage	240 kV
Maximum continuous voltage	250 kV
Short circuit withstand capability	30 kA symmetrical (minimum)

The interrupting capability and/or short circuit withstand capability of the proposed equipment is higher than the short circuit levels currently in this area (presented in Table 8 of the addendum to the final SIA report for CAA_ID 2014-514).

Table 10: 230 kV shunt reactors R3 and R4 at Marathon TS:

Rated voltage	230 kV
Rated capability	65 Mvar @ 250 kV
Configuration	Wye grounded
Surge Capacitor (in case of air-core reactor)	35 nF per phase

Table 11: 230 kV shunt reactor R1 Lakehead TS:

Rated voltage	230 kV
Rated capability	125 Mvar @ 250 kV
Configuration	Wye grounded
Surge Capacitor (in case of air-core reactor)	35 nF per phase

Table 12: 230 kV shunt capacitor SC21 Lakehead TS:

Rated voltage	230 kV
Rated capability	125 Mvar @ 250 kV
Configuration	Double wye Ungrounded
Series Reactor	3.3 mH per phase
Surge Capacitor	35 nF per phase

Note: The new ground switches for new circuits M37L, M38L, W35M and W36M will be interrupter-type. The new ground switches for M23L and M24L at Marathon TS will be interrupter-type. The other new ground switches for W21M, W22M, M23L and M24L will be motor-operated air-break type.

The equipment proposed by the connection applicant for the project satisfies all applicable requirements and as such it is acceptable to the IESO.

3.2 Models of the Proposed Equipment

The station configurations proposed by the connection applicant were modelled in PSS/E for this study.

– End of Section –

4. System Impact Assessment

This System Impact Assessment (SIA) focused exclusively on the area from Lakehead TS to Marathon TS to Wawa TS that will be directly affected by the project. The following aspects were assessed:

1. Steady state voltage and voltage stability (Section 4.3) to confirm that the proposed upgrades are sufficient to achieve the desired westward transfer capability of 450 MW;
2. Equipment loading (Section 4.4) to confirm that existing equipment is adequate for the desired westward transfer capability of 450 MW;
3. Operability assessment (Section 4.5) to confirm that local voltages can be maintained within the required range under all foreseeable operating conditions;
4. Protection Impact Assessment (PIA), attached to this report, performed by the connection applicant on behalf of the IESO; and
5. Relay margin analysis (Section 4.6), based on the results of the PIA.

The following Sections present the Standards and Criteria used in this study (Section 4.1); the Study Assumptions (Section 4.2); and the Study Results (Sections 4.3 to 4.6).

4.1 Standards and Criteria

The project was assessed against the NERC TPL-001 criteria for the loss of up to two elements. The following table lists all the conditions studied and associated fault types.

Table 13: Contingency and fault types respected as per the NERC TPL-001 criteria

Conditions:	Fault Type
All elements I/S: Loss of one element	3 phase fault
All elements I/S: Loss of two elements (breaker failure)	LG fault
All elements I/S: Loss of two elements (tower contingency)	LG fault on different phase of adjacent circuits

The voltage, equipment loading and transient performance of the integrated power system was evaluated against the following Ontario Resource and Transmission Assessment Criteria (ORTAC):

- Voltage decline of 10% or less for both pre and post ULTC action is acceptable (section 4.3).
- Minimum pre-contingency voltages on 230 kV and 115 kV buses are 220 kV and 113 kV, respectively (section 4.2).
- Maximum pre-contingency voltages on 230 kV and 115 kV buses are 250 kV and 127 kV, respectively (section 4.2).
- Minimum post-contingency voltages on 230 kV and 115 kV buses are 207 kV and 108 kV, respectively (section 4.3).
- Maximum post-contingency voltages on 230 kV and 115 kV buses are 250 kV and 127 kV (section 4.3).
- Steady state voltage stability must be demonstrated such that the maximum acceptable pre-contingency power transfer must be 10% lower than the voltage instability point of the pre-contingency P-V curve and 5% lower than the voltage instability point of the post-contingency P-V curve (section 4.5).

- With all transmission facilities in service, equipment loading must be within continuous ratings, with any one element out of service, equipment loading must be within applicable long-term emergency (LTE) ratings and with any two elements out of service, equipment loading must be within applicable short-term emergency (STE) ratings (section 7.1).
- All line and equipment loads shall be within their continuous ratings with all elements in service and within their LTE ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their STE ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the LTE ratings (section 4.7.2).
- The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not remain below 80% of nominal voltage for more than 250 ms within 10 s following a fault (section 4.4).

For the relay margin analysis the following criteria, listed in Market Manual 7.4: IESO-Controlled Grid Operating Policies (section 4.3.9) was used:

- Following fault clearance or the loss of an element without a fault, the margin on all instantaneous and timed distance relays that are part of the BES or BPS, including generator loss of excitation and out-of-step relaying at major generating stations, must be at least 20% and 10% respectively.
- The margin on all relays at local system stations, generator loss of excitation and out-of-step protections on small generating units, or those associated with transformer backup protections, must be at least 15% on all instantaneous relays and 0% on all timed relays having a time delay setting less than or equal to 0.4 seconds.
- For all relays having a time delay setting greater than 0.4 seconds, the apparent impedance may enter the timed tripping characteristic, provided that there is a margin of 50% on time. For example, the apparent impedance does not remain within the tripping characteristic for a period of time greater than one-half of the relay time delay setting.
- The margin on all system relays, such as change of power relays, must be at least 10%.

4.2 Study Assumptions

The main study assumptions are listed below:

Generation Assumptions:

- In the Northwest transmission zone, the output from the existing hydroelectric facilities was set to 342 MW, representing approximately 40% of their peak output. This would be in the range expected from these hydroelectric facilities during a drought year. A further contribution of 77 MW was also assumed to be available from the existing thermal facilities in this zone, resulting in a total zone generation of 419 MW**.** Atikokan GS and Thunder Bay GS biomass fired thermal facilities and the Greenwich WGS were assumed to be out-of-service.
- In the Northeast transmission zone, the output from the existing hydroelectric facilities was set to 1397 MW, representing approximately 47% of their peak output. This would be in the range expected from these hydroelectric facilities during a drought year. The existing thermal generation in the area was assumed to contribute a further 406 MW (around 50% of their maximum), wind at 70 MW (20% of its maximum) and solar at 41 MW (77% of its maximum) for a total generation in the zone of 1915 MW.
- The dispatch of generation in southern Ontario has negligible impact on the project and as such a generic dispatch corresponding to peak summer conditions was used.

Load Assumptions:

- In the Northwest transmission zone, the peak load of about 797 MW was selected to reflect the current long term forecast under the "Low Growth" scenario of the IESO's need update report[2] dated December 15, 2015. This load level would give a peak demand of approximately 876 MW once the transmission losses of approximately 78 MW have been factored in.
- The load in Northeast was set to 1150 MW which yields a peak demand of approximately 1240 MW once the transmission losses of approximately 90 MW were factored in.
- Demand in southern Ontario has negligible impact on the project and as such a generic summer peak demand was used.

Transfers on the East-West Tie and on the Sudbury Flow West Interface

The demand and generation assumptions in the Northwest and Northeast transmission zones resulted in:

- A Sudbury Flow West (SFW) transfer of 317 MW;
- A Flow into Wawa TS of 468 MW;
- An East-West Tie transfer of 463 MW westwards;
- A Flow from Marathon TS to Lakehead TS of 427 MW; and
- A Flow from Lakehead TS to MacKenzie TS of 127 MW.

The phase-angle-regulators on the interconnections with Minnesota and Manitoba were adjusted to achieve zero transfers.

4.3 Steady-State Voltage and Voltage Stability

The voltage performance of the reinforced East-West Tie was evaluated by using PV-Analysis to determine the voltage stability limits, after applying the required margins, under different contingency conditions. The selected contingency conditions involved the loss of either the existing or the new double circuit transmission lines on each section of the reinforced East-West Tie and associated NW SPS 2 actions. These represent the most critical contingencies for the East-West Tie.

The voltage stability limits were then compared with the relevant pre- or post-contingency East-West Tie transfers to confirm that they were always greater, and therefore would not be restrictive.

The following table summarizes the results of the voltage stability analysis. For all the scenarios studied, the Voltage Stability Limit exceeded the recorded pre- or post-contingency flow, as reflected in the positive values for the 'Additional Margins'.

The results therefore confirm that with the additional reactive support that the connection applicant proposed to install as part of the project at each terminal transformer station, the reinforced East-West Tie will be able to achieve the targeted transfer of 450 MW westwards.

[2] This report is available on Ontario Energy Board's website at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2011-0140&sortd1=rs_dateregistered&rows=200

Table 14: Summary of voltage stability results

Scenario:	East-West Tie flow (MW)	Flow at the point of voltage instability (MW)	Voltage Stability Limit (MW)	Additional Margin (MW)
All elements in service, pre-contingency	463.8	627.8	565.0	101.2
Post M23L+M24L contingency	474.5	589.1	559.6	85.1
Post M37L+M38L contingency	481.9	600.7	570.7	88.8
Post W21M+W22M contingency	472.8	577.0	548.2	75.4
Post W35M+W36M contingency	480.5	604.8	574.6	94.1
Post P25W+P26W contingency	465.7	546.3	519.0	53.3

In table 14:

- "East-West Tie flow" is the pre or post contingency flow across the interface, measured at Wawa TS, in each of the study scenarios;
- "Flow at the point of voltage instability" is the transfer at which the load flow analysis failed to converge;
- "Voltage Stability Limit" is determined by applying a margin of either 10% for the pre-contingency case or 5% for the post-contingency cases to the "Flow at the point of voltage instability"; and
- "Additional Margin" is the difference between the "Voltage Stability Limit" and the "East-West Tie flow". A positive value indicates that the ORTAC criteria are satisfied.

Additional results of the P-V analysis are presented in Appendix A.

Load flow analysis, that included any NW SPS 2 actions that were necessary to control the amount of reactive compensation that would remain in-service to support the post-contingency transfers (more details are available in Section 4.4) was used to determine the pre- and post-contingency voltages on all 230 kV buses west of, and including, Wawa TS. These were checked for compliance with ORTAC.

As shown in the following table, no voltage level or voltage change violations were identified.

Table 15: Summary of voltage levels and voltage changes

Scenario	Pre-contingency	Loss of M23L+M24L				Loss of M37L+M38L			
		Pre tap action		Post tap action		Pre tap action		Post tap action	
Monitored bus:		Voltage (kV)	Change (%)	Voltage (kV)	Change (%)	Voltage (kV)	Change (%)	Voltage (kV)	Change (%)
MacKenzie 230 kV	246.1	247.6	0.61%	246.9	0.33%	247.3	0.49%	246.8	0.28%
Lakehead 230 kV	243.0	244.8	0.74%	243.0	0.00%	244.2	0.49%	243.0	0.00%
Marathon 230 kV	240.8	241.9	0.46%	238.7	-0.87%	245.2	1.83%	241.6	0.33%
Wawa 230 kV	243.5	244.6	0.45%	242.0	-0.62%	246.4	1.19%	243.4	-0.04%

Table 15 (contd.): Summary of voltage levels and voltage changes

Scenario	Pre-contingency	Loss of W21M+W22M				Loss of W35M+W36M			
		Pre tap action		Post tap action		Pre tap action		Post tap action	
Monitored bus		Voltage (kV)	Change (%)	Voltage (kV)	Change (%)	Voltage (kV)	Change (%)	Voltage (kV)	Change (%)
MacKenzie 230 kV	246.1	247.3	0.49%	246.9	0.33%	246.5	0.16%	246.8	0.28%
Lakehead 230 kV	243.0	244.1	0.45%	243.0	0.00%	243.0	0.00%	243.0	0.00%
Marathon 230 kV	240.8	247.9	2.95%	245.9	2.12%	245.4	1.91%	244.6	1.58%
Wawa 230 kV	243.5	246.5	1.23%	244.6	0.45%	246.9	1.40%	246.2	1.11%

The largest post-contingency voltage change (2.95% - on the Marathon TS 230 kV bus following the loss of W21M and W22M) is within the IESO criteria.

4.4 Equipment Loading Assessment

An assessment was performed to confirm that the existing 115 kV circuits A5A, A1B and T1M between Alexander SS and Marathon TS are adequate for westward transfers of 450 MW across the East-West Tie). The results are presented in the following table:

Table 16: Summary of equipment loading results

Scenario				All I/S	Post M24L	Post M37L	Post M23L+M24L	Post M37L+M38L
Line	From	To	LTE	A	A	A	A	A
T1M	Marathon TS	Pic jct	460	232	272	276	351	370
T1M	Pic jct	Angler’s jct	460	205	245	249	324	343
T1M	Angler’s jct	Terrace Bay	460	205	245	249	324	343
A1B	Terrace Bay	Ter Bay jct	570	204	244	248	323	342
A1B	Ter Bay jct	Aguasabon SS	570	129	154	156	207	223
A5A	Aguasabon SS	Schreiber jct	430	130	169	173	241	260
A5A	Schreiber jct	Minnova jct	430	119	157	160	227	245
A5A	Minnova jct	Alexander_SS	430	114	152	156	223	242
M23L	Marathon TS	Greenwich jct*	940	235	306	312	0	461
M24L	Marathon TS	Greenwich jct*	1020	235	0	312	0	461
M37L	Marathon TS	Lakehead TS	1564	245	320	0	453	0
M38L	Marathon TS	Lakehead TS	1564	245	320	327	453	0

* most limiting section of the line.

To simplify the reporting only the LTE of the most limiting sections is presented (the pre-contingency results with all elements in service are shown for reference only as they’re all within the continuous ratings of the monitored circuits). All post-contingency flows, with one and two elements out of service are within the LTE of the 115 kV circuits, an indication that upgrading these circuits can be postponed until it is required, as the connection applicant indicated.

4.5 Operability Assessment

An assessment was performed for this project to identify an operating philosophy for the reactive devices in the area and to confirm that the appropriate reactive devices and controls are in place to maintain voltages within applicable ranges under all foreseeable conditions. The nature of the East-West tie, consisting of multiple, very long transmission circuits subjected to flows that can range from zero to maximum in either direction on a daily basis, presents many operational challenges.

The suggested operating philosophy for the reactive devices near the East-West tie is the following:

1. Put sufficient reactors in service at all times to compensate for the additional reactive contribution of the in service (new or existing) transmission circuits and switch the shunt capacitors, as required, to provide the appropriate level of reactive support for the prevailing transfers.
2. Arm NW SPS 2 such that in-service capacitors are switched out following the loss of reactors or autotransformers and in-service reactors are switched out following the loss of transmission circuits.

To confirm that the reactive compensation being proposed would be adequate to maintain acceptable pre- and post-contingency voltages at all transfer levels, three scenarios, with all elements in service, pre-contingency, were prepared:

1. Targeted westwards transfer: 450 MW
2. Median westwards transfer: 225 MW
3. Zero transfer.

Detailed diagrams of these three scenarios are available in Appendix B.

This study was completed only for load supply scenarios under transfers westwards because they would require the minimum number of local generators to be on-line, which is a worst case for voltage control.

In Section 4.3 contingencies involving the loss of circuits were investigated; accordingly only the loss of reactive control devices and autotransformers were considered in this section. The following table shows the post-contingency voltage levels on the main 230 kV and 115 kV buses following different contingencies with an East-West Tie transfer of 450 MW – Scenario #1. The contingencies include the loss of a reactor (RX) and/or an autotransformer (ATX), or the loss of one autotransformer while the companion autotransformer is already out of service (for maintenance, repair or following a fault). At Marathon TS, where two 230 kV reactors are to be installed, the loss of both reactors was examined.

Table 17: Summary of voltage levels (kV) - Scenario #1

Terminal Station		Wawa TS		Marathon TS		Lakehead TS		MacKenzie TS
Autotransformer/Reactor Outages		230 kV	115 kV	230 kV	115 kV	230 kV	115 kV	230 kV
Pre-contingency		244	124	241	125	243	123	246
Wawa TS	1 ATX out	245	124	242	126	243	124	247
	2 ATXs out	244	N/A	241	126	243	124	247
Marathon TS	1 ATX out	244	125	241	126	243	123	246
	2 ATXs out	243	124	241	122	243	124	247
	1 ATX & 1 RX out	246	126	246	126	243	123	246
	2 RXs out	247	125	247	123	243	125	247
Lakehead TS	1 ATX out	244	124	241	125	243	123	247
	2 ATXs out	244	123	237	124	235	121	235
	1 ATX & 1RX out	244	124	242	124	243	125	247

Consistent with the operating philosophy presented above, NW SPS 2 actions were required for some of these contingencies, examples being:

- tripping of the tertiary-connected capacitors at Marathon TS following the loss of the 230 kV Marathon TS reactor assuming the first 230 kV reactor is out of service pre-contingency for maintenance or repairs;
- load rejection of around 100 MW to maintain post-contingency stability in the Lakehead TS 115 kV area following the loss of the second Lakehead TS transformer assuming the first one out of service pre-contingency for maintenance or repairs; or
- tripping of the Lakehead TS 230 kV capacitor following the loss of the Lakehead TS reactor.

The following table shows the results for Scenario #2:

Table 18: Summary of voltage levels (kV) - Scenario #2

Terminal Station		Wawa TS		Marathon TS		Lakehead TS		MacKenzie TS
Autotransformer/Reactor Outages		230 kV	115 kV	230 kV	115 kV	230 kV	115 kV	230 kV
Pre-contingency		245	124	243	125	243	124	248
Wawa TS	1 ATX out	245	124	243	125	243	124	248
	2 ATXs out	250	N/A	246	126	243	124	248
Marathon TS	1 ATX out	245	124	244	124	243	124	248
	2 ATXs out	246	124	246	122	243	124	248
	1ATX & 1 RX out	247	125	248	125	243	123	248
	2 RXs out	247	124	250	123	243	124	248
Lakehead TS	1 ATX out	244	124	243	124	242	124	247
	2 ATXs out	246	124	246	124	247	116	247
	1 ATX & 1RX out	239	124	238	124	243	125	248

NW SPS 2 actions were required for some of these contingencies, examples being:

- tripping of all the tertiary-connected capacitors at Marathon TS and Wawa TS following the loss of the second Marathon TS 230 kV reactor assuming that the first 230 kV reactor is out of service pre-contingency for maintenance or repairs;
- load rejection of around 50 MW to maintain post-contingency stability in the Lakehead TS 115 kV area following the loss of the second Lakehead TS transformer assuming that the first autotransformer is out of service pre-contingency for maintenance or repairs;
- tripping of the Lakehead TS 230 kV capacitor following the loss of the Lakehead TS reactor; or
- tripping of the Lakehead TS 230 kV capacitor and all tertiary-connected capacitors at Marathon TS and Wawa TS following the loss of the Lakehead TS reactor assuming that one Lakehead TS autotransformer is out of service pre-contingency for maintenance or repairs.

The following table shows the results for Scenario #3:

Table 19: Summary of voltage levels (kV) – Scenario #3

Station		Wawa TS		Marathon TS		Lakehead TS		MacKenzie TS
Autotransformer/Reactor Outages		230 kV	115 kV	230 kV	115 kV	230 kV	115 kV	230 kV
Pre-contingency		241	123	242	124	243	124	245
Wawa TS	1 TX out	244	123	244	125	243	124	245
	2 TXs out	249	N/A	245	124	243	124	245
Marathon TS	1 TX out	242	123	243	123	243	124	245
	2 TXs out	243	124	246	125	243	124	245
	1 TX & 1 RX out	247	125	248	124	243	124	248
	2 RXs out	245	125	249	124	243	124	245
Lakehead TS	1 TX out	241	123	241	124	241	124	243
	2 TXs out	242	124	243	125	245	120	245
	1 TX & 1RX out	243	124	246	126	249	124	248

NW SPS 2 actions for scenario #3 were limited to tripping the in-service tertiary-connected capacitor at Marathon TS following the loss of the second Wawa TS autotransformer or the second Marathon TS reactor.

The analysis shows that the proposed voltage control devices will be appropriate to maintain local voltages within applicable ranges under high, median and zero transfers across the East-West Tie interface and as such it is expected that they will be adequate for all other intermediate flow levels. A switching study was completed to determine if these reactive devices are properly sized. Scenarios #2 was used for these tests as these devices will most likely be switched in or out under median transfer levels to prepare for increasing or decreasing transfers. Table 19 below summarizes the voltage changes following reactive device switching at the main stations:

Table 20: Summary of voltage changes following reactive devices switching

Station	Switched Equipment	Wawa TS		Marathon TS		Lakehead TS		MacKenzie TS
		230 kV	115 kV	230 kV	115 kV	230 kV	115 kV	230 kV
Lakehead TS	230 kV Capacitor-off	0.12%	0.09%	0.23%	0.10%	0.43%	1.99%	0.15%
	230 kV Capacitor-on	0.12%	0.09%	0.23%	0.10%	0.43%	2.03%	0.15%
	230 kV Reactor-off	0.33%	0.24%	0.62%	0.52%	1.10%	1.20%	0.57%
	230 kV Reactor-on	0.33%	0.24%	0.62%	0.52%	1.08%	1.21%	0.57%
Marathon TS	230 kV Reactor-off	1.92%	1.63%	3.11%	2.87%	1.91%	1.61%	1.23%
	230 kV Reactor-on	1.88%	1.61%	3.01%	2.79%	1.88%	1.58%	1.21%
	Tertiary Reactor-off	1.18%	1.01%	1.93%	3.46%	1.23%	1.06%	0.79%
	Tertiary Reactor-on	1.17%	1.00%	1.89%	3.35%	1.22%	1.05%	0.79%
	Tertiary-Capacitor-off	0.87%	0.74%	1.42%	2.56%	0.91%	0.78%	0.59%
	Tertiary-Capacitor-on	0.88%	0.75%	1.44%	2.63%	0.92%	0.79%	0.59%
Wawa TS	Tertiary Reactor-off	1.36%	2.59%	0.99%	0.92%	0.61%	0.51%	0.39%
	Tertiary Reactor-on	1.34%	2.52%	0.98%	0.91%	0.60%	0.51%	0.39%
	Tertiary-Capacitor-off	1.06%	2.02%	0.77%	0.71%	0.47%	0.40%	0.30%
	Tertiary-Capacitor-on	1.07%	2.06%	0.78%	0.72%	0.48%	0.40%	0.31%

In order to highlight the importance of the dynamic voltage support provided by the Lakehead TS synchronous condenser and SVC, the following switching tests were performed assuming both devices are unavailable:

Table 21: Summary of voltage changes in absence of dynamic support

Station	Switched Equipment	Wawa TS		Marathon TS		Lakehead TS		MacKenzie TS
		230 kV	115 kV	230 kV	115 kV	230 kV	115 kV	230 kV
Lakehead TS	230 kV Capacitor-off	2.43%	2.05%	4.01%	3.83%	6.30%	5.39%	4.01%
	230 kV Capacitor-on	2.29%	1.94%	3.75%	3.58%	5.81%	5.00%	3.75%
	230 kV Reactor-off	2.43%	2.05%	4.01%	3.83%	6.30%	5.39%	4.01%
	230 kV Reactor-on	2.29%	1.94%	3.75%	3.56%	5.81%	5.00%	3.75%

This test shows that if the SVC and synchronous condenser at Lakehead are not available, the voltage change that occurs when switching either the Lakehead 230 kV reactor or capacitor will be beyond criteria (violations shown in red on table 21 above).

With just one of the SVC or the synchronous condenser available, the voltage change that occurs when switching either the Lakehead 230 kV reactor or capacitor will be within criteria only if there is sufficient dynamic range on the available SVC or synchronous condenser prior to the switching. It should be noted that under some system conditions, to create sufficient dynamic range, operators may need to switch smaller reactors or capacitors at adjacent transformer stations.

This section demonstrated that the proposed reactive control devices are appropriate to control voltages within applicable range under all foreseeable conditions. Since the voltages near the project are strongly dependent on the flows across the tie and because the flows across the tie can vary over a wide range throughout the day, these reactive control devices may need to be switched multiple times a day. The ability to remotely arm NW SPS 2 directly from the IESO control room will help simplify this process.

4.6 Relay Margin and Transient Stability Analysis

The relay margin analysis is required to ensure that out of zone tripping does not occur as a result of the addition/modification of power system equipment or modifications to protection settings.

The analysis is performed by simulating contingencies on elements in the vicinity of the line whose relay margin is being assessed and determining the associated trajectory of the apparent line impedance. To check if the required relay margin is maintained after the simulated fault is cleared, the trajectory of the apparent line impedance is compared to the relay characteristic of the line(s) that are not expected to trip.

The protection impact assessment (PIA) performed by the transmitter on behalf of the IESO indicates that existing protections setting at the three terminal transformer stations modified by the project remain unchanged and provides the settings of the new protections proposed to be installed for the new double circuit line. It also indicates that no other protections in the zone require modifications for this project's incorporation.

In order to assess the relay margins for the new and existing relays at Lakehead TS, Marathon TS and Wawa TS the following representative contingencies were simulated:

1. Three phase fault (clearing time: local - 83 ms, remote - 108 ms) followed by the loss of one transmission circuit:
    a. M23L at Lakehead TS and at Marathon TS (2 cases)
    b. M37L at Lakehead TS and at Marathon TS (2 cases)
    c. W22M at Marathon TS and at Wawa TS (2 cases)

   d. W35M at Marathon TS and at Wawa TS (2 cases)

2. Line-to-line-to-ground (LLG) fault (clearing time: local - 83 ms, remote - 108 ms) followed by the loss of 2 adjacent transmission circuits:
   a. M23L and M24L at Lakehead TS and Marathon TS (2 cases)
   b. M37L and M38L at Lakehead TS and Marathon TS (2 cases)
   c. W21M and W22M at Marathon TS and Wawa TS (2 cases)
   d. W35M and W36M at Marathon TS and Wawa TS (2 cases)
3. Line-to-ground (LG) fault and breaker failure - stuck breaker - (clearing time: remote - 108 ms, total - 181 ms) followed by the loss of two transmission circuits:
   a. L22L23 breaker failure at Lakehead TS followed by the loss of M23L and A22L (1 case)
   b. L21L23 breaker failure at Marathon TS followed by the loss of M23L and W21M (1 case)
   c. L22L24 breaker failure at Marathon TS followed by the loss of W22M and M24L (1 case)
   d. L22L26 breaker failure at Wawa TS followed by the loss of W22M and P26W (1 case)
   e. L21L25 breaker failure at Wawa TS followed by the loss of W21M and P25W (1 case)
   f. L35L36 breaker failure at Wawa TS followed by the loss of W35M and W36M (1 case)

These faults were simulated assuming the desired westward flow of approximately 450 MW across the East-West Tie to also confirm that the local system is transiently stable following a recognized contingency.

The analysis shows that the relay margins and post-contingency transient voltages satisfy the IESO's criteria, an indication that the proposed protection modifications, as presented in the PIA, are acceptable to the IESO.

Appendix C presents some sample results of the relay margin analysis.

4.7 Remedial Action Scheme NW SPS 2

As a result of project, the connection applicant has proposed revisions to the existing NW SPS 2, corresponding to the new facilities and new station configurations, as well as addition of new contingencies and actions to facilitate the operations of the IESO-controlled grid and help with the re-preparation of the grid within 30 minutes following contingencies. The revisions proposed to the existing NW SPS 2 (CAA ID 2014-EX712) include:

1. Add 10 new single and double contingencies involving 230 kV transmission circuits:
   - W35M, W36M and W36M+W36M;
   - M37L, M38L and M37L+M38L;
   - P25W, P26W and P25W+P26W; and
   - W23K.
2. Remove 4 Marathon TS breaker failure contingencies;
3. Remove 4 Lakehead TS breaker failure contingencies;
4. Add 2 new contingencies "Lakehead TS Reactor R1" and "Lakehead TS Capacitor SC21;
5. Replace 2 Lakehead TS transformer (T7 and T8) contingencies with one "Lakehead TS T7 <u>OR</u> T8" contingency (i.e., trip of one of the two transformers);
6. Add 2 new transformer contingencies "Marathon TS T11 <u>OR</u> T12" and "Wawa TS T1 <u>OR</u> T2" (i.e., trip of one of the two transformers at each station) ;
7. Add 5 new actions to:

- Trip Marathon TS 230 kV reactor R3;
- Trip Marathon TS 230 kV reactor R4;
- Trip Lakehead TS 230 kV reactor R1;
- Trip Lakehead TS 230 kV capacitor SC21; and
- Trip Lakehead TS 115 kV capacitor SC11.

8. Remove 115 kV transmission circuit A5A cross-trip action.

The final choice of contingencies and responses of NW SPS 2 is presented below:

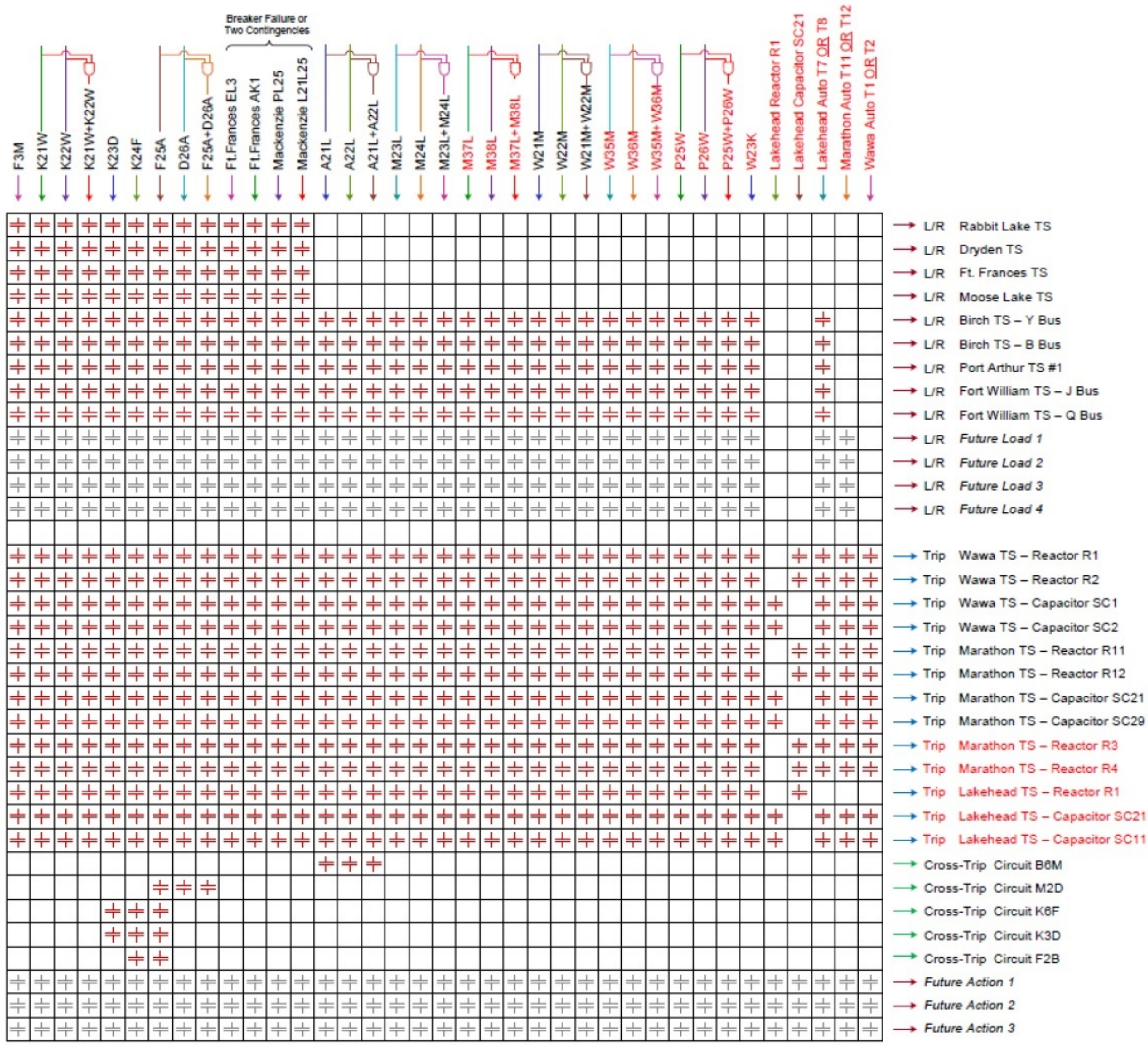

Figure 4: Proposed modification to the existing NW SPS 2

The modifications proposed for NW SPS 2 are acceptable to the IESO.

– End of Section –

Appendix A: P-V Analysis Results

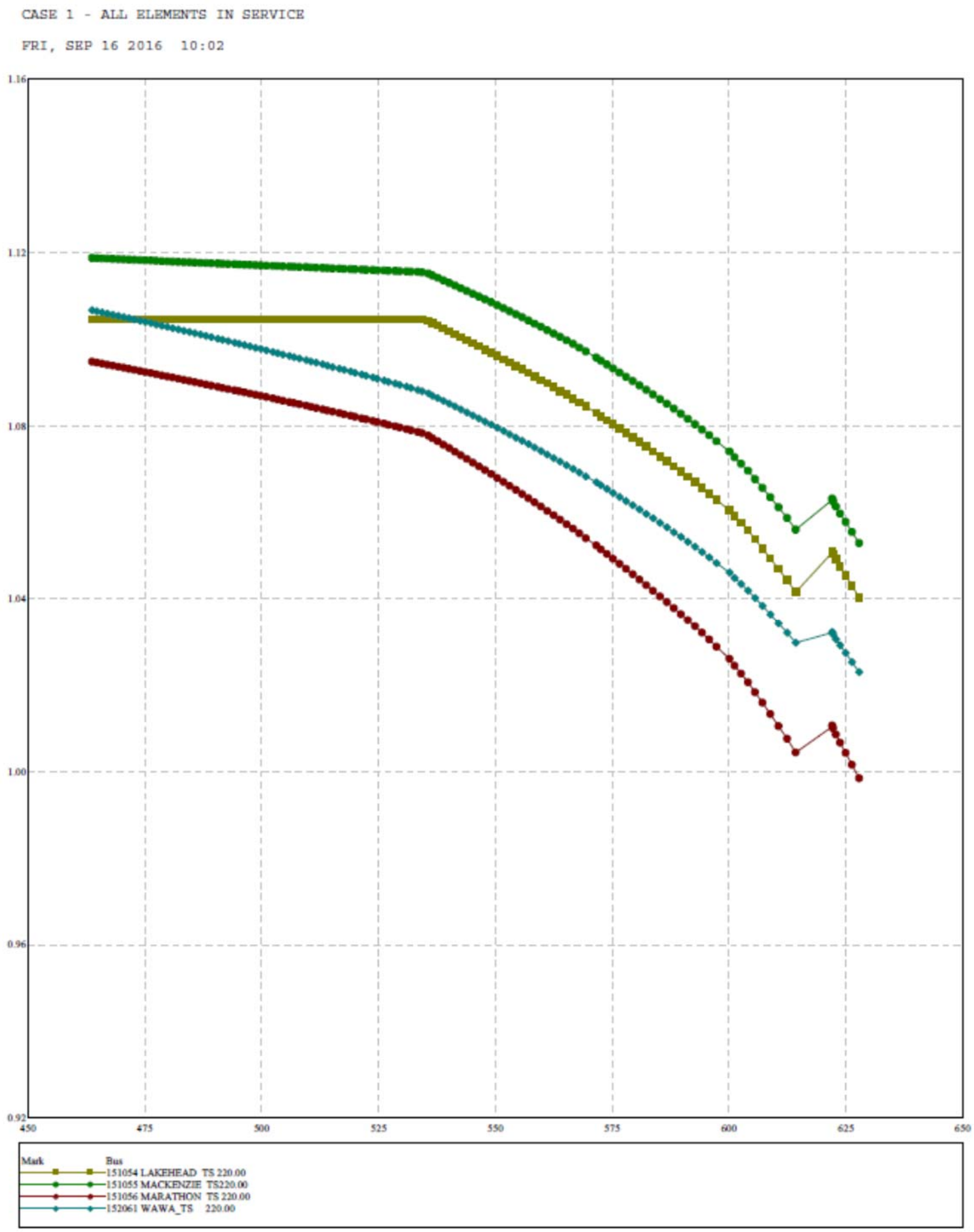

Figure 5: PV - all elements in service, pre-contingency

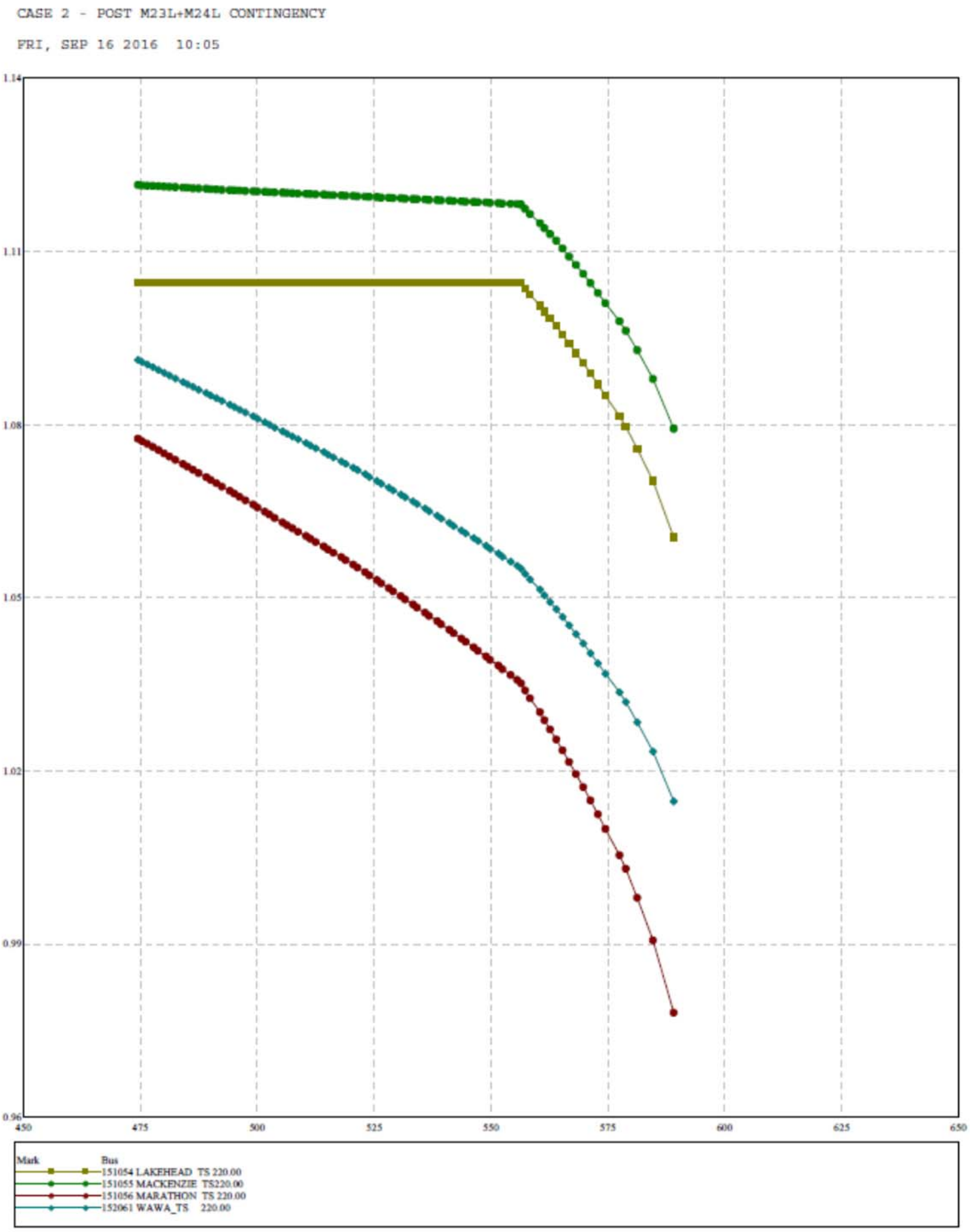

Figure 6: PV - post M23L+M24L contingency

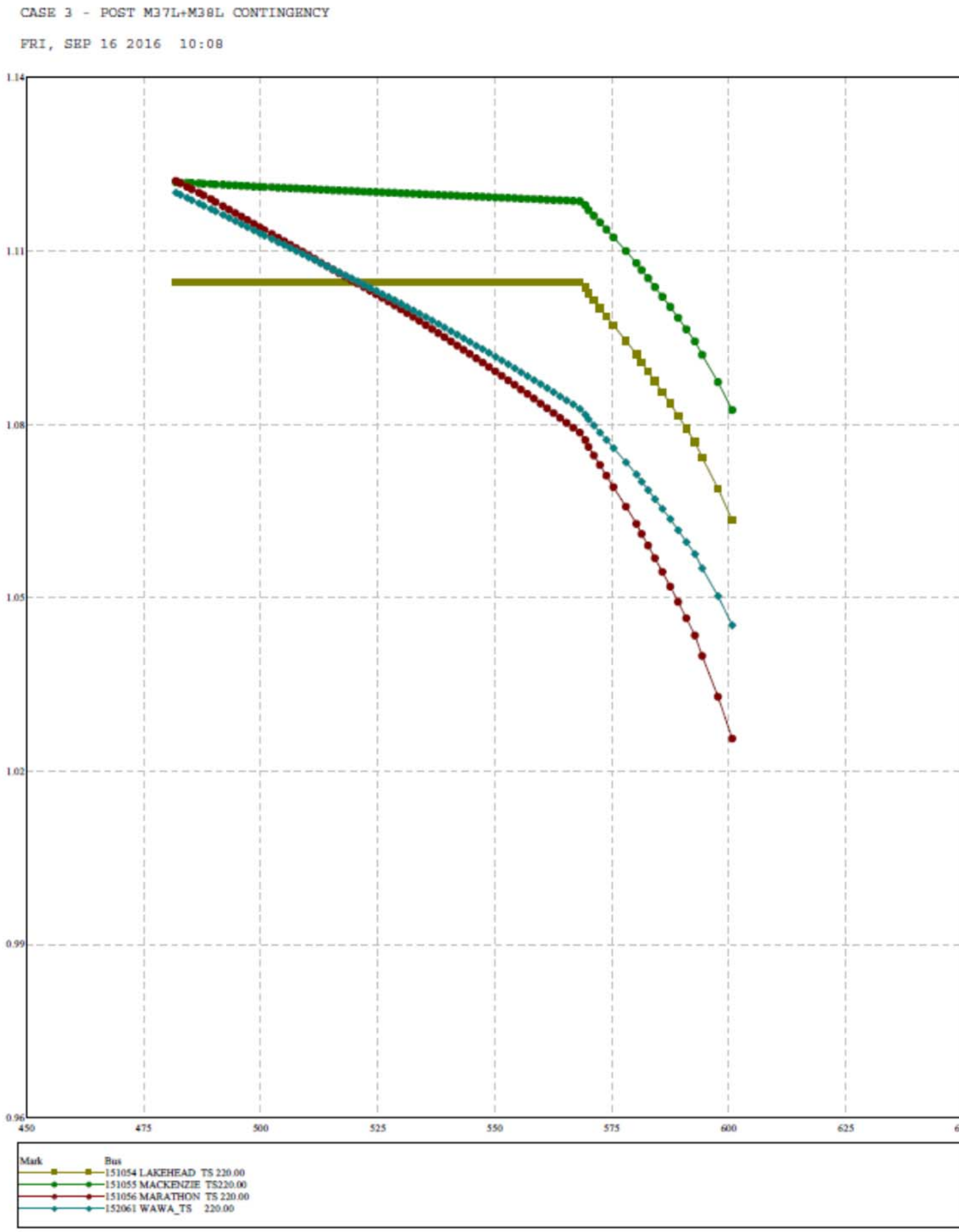

Figure 7: PV - post M37L+M38L contingency

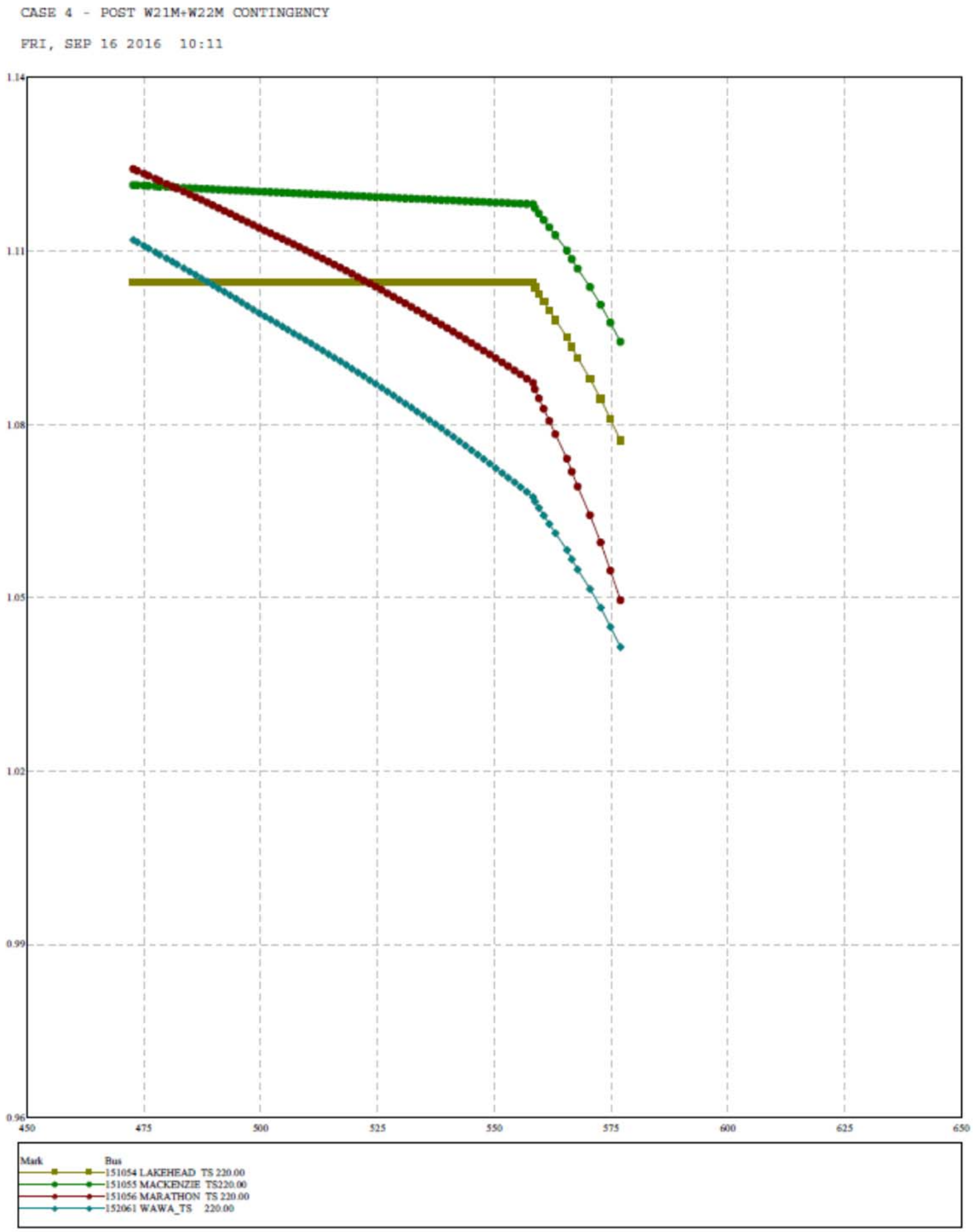

Figure 8: PV - post W21M+W22M contingency

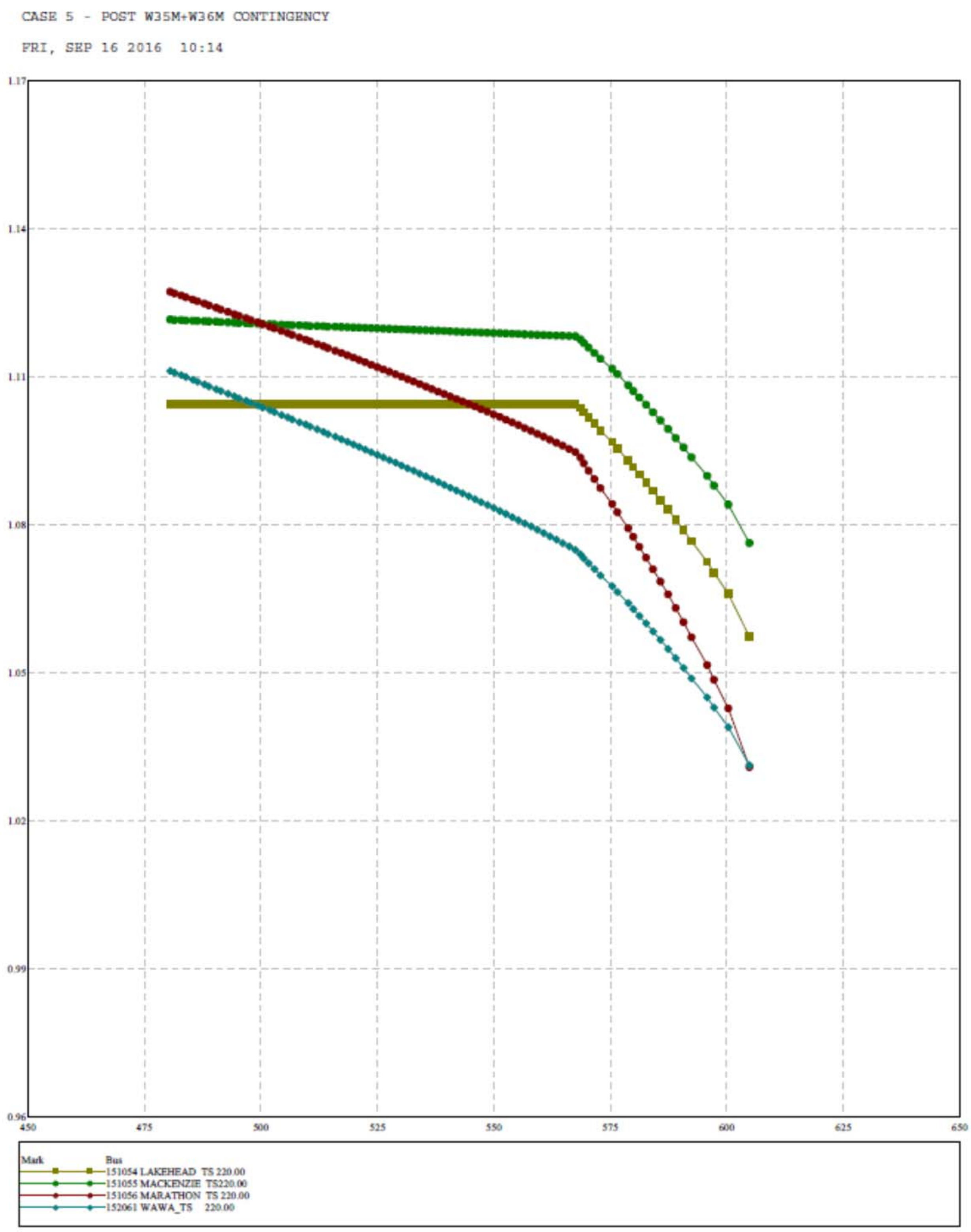

Figure 9: PV - post W35M+W36M contingency

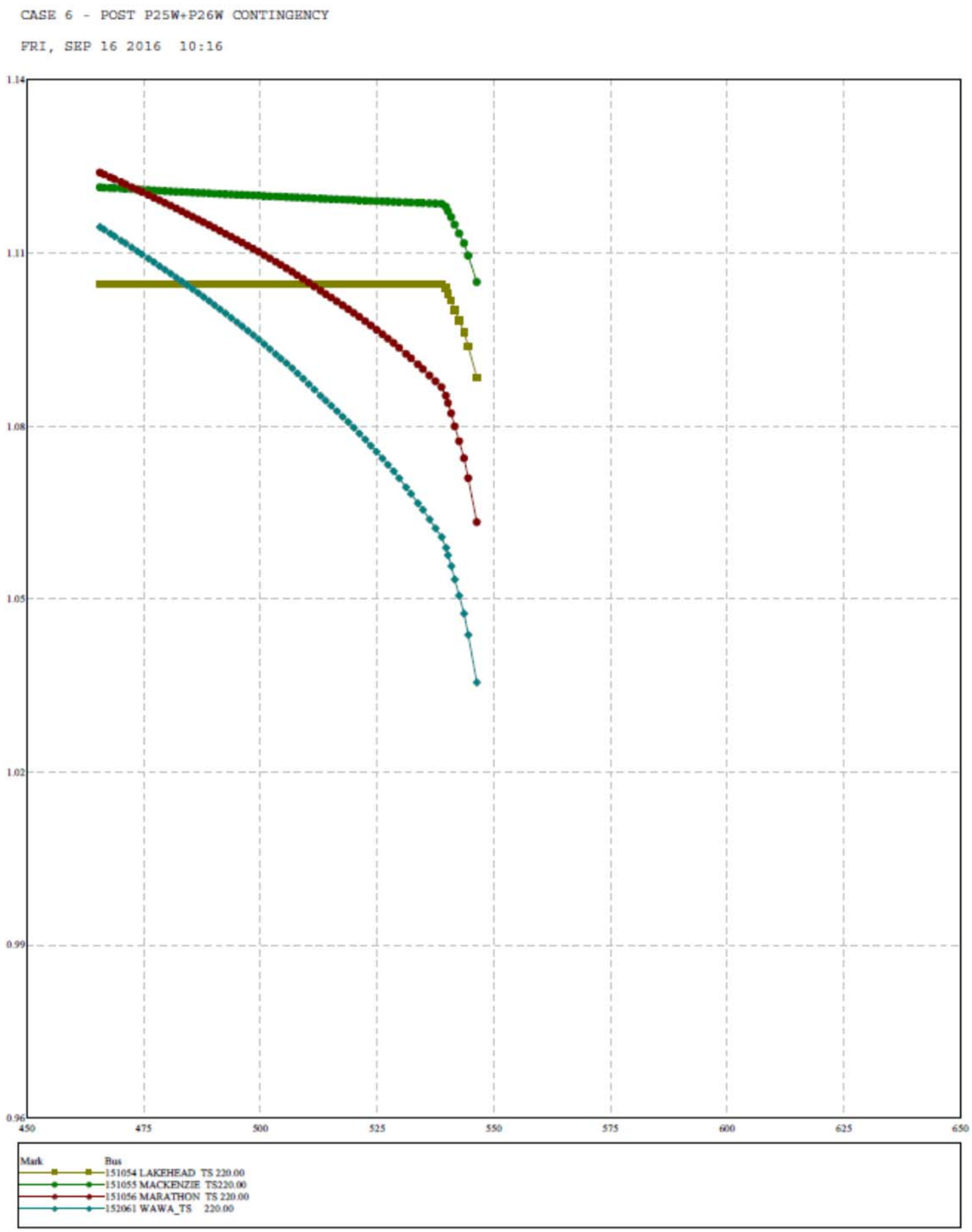

Figure 10: PV - post P25W+P26W contingency

– End of Section –

Appendix B: Power flow scenarios used in this study

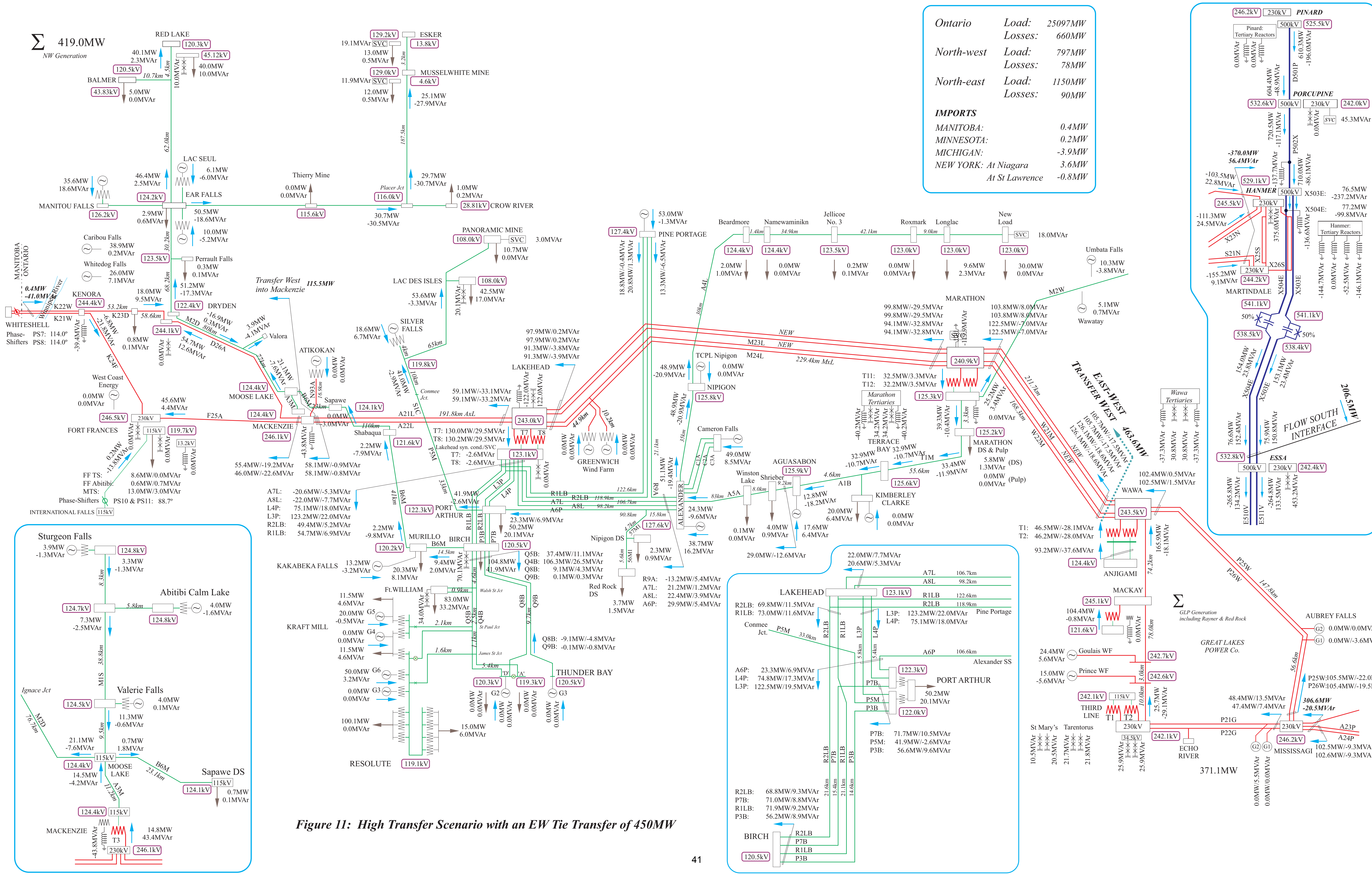

Figure 11: High Transfer Scenario with an EW Tie Transfer of 450MW

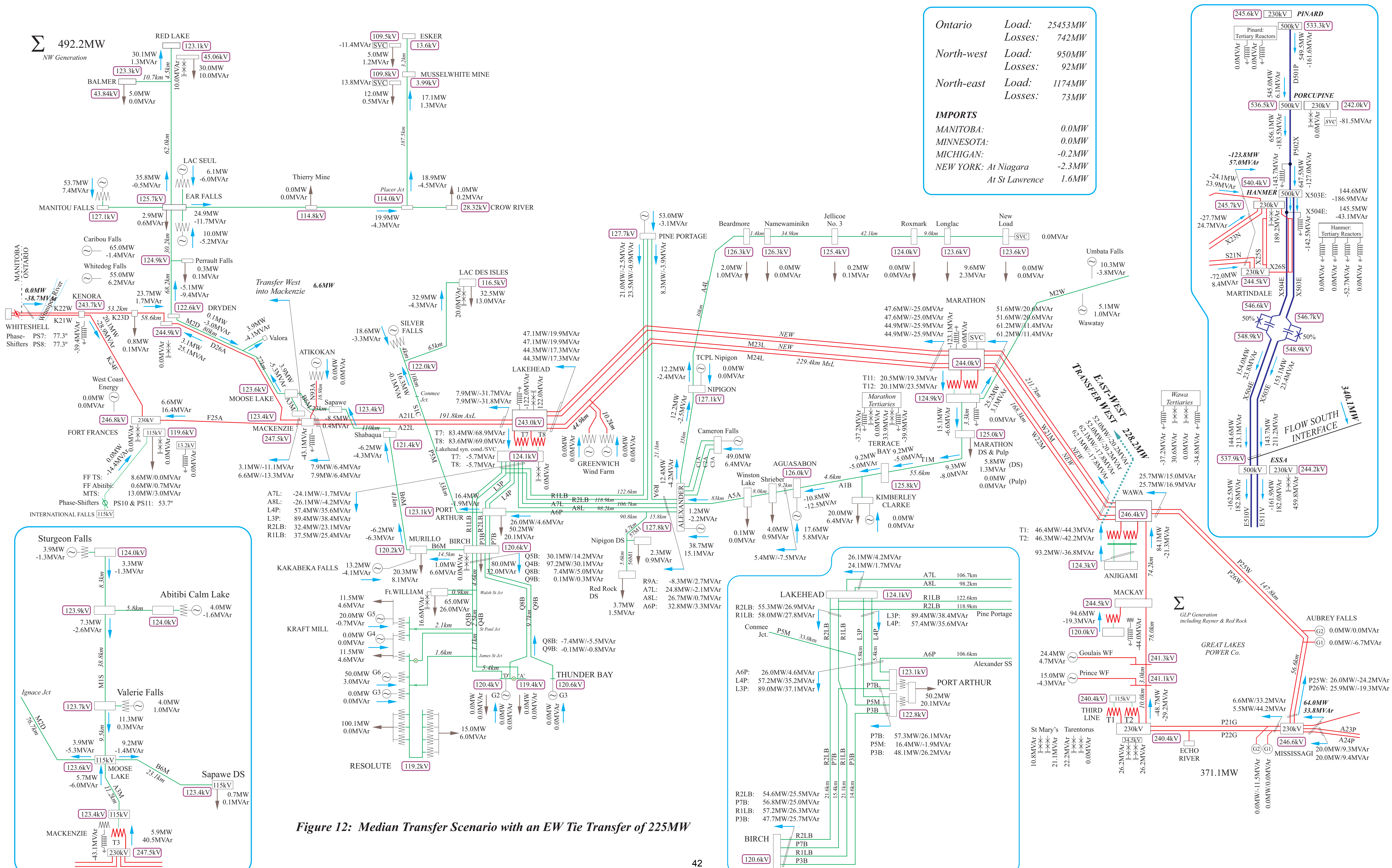

Figure 12: Median Transfer Scenario with an EW Tie Transfer of 225MW

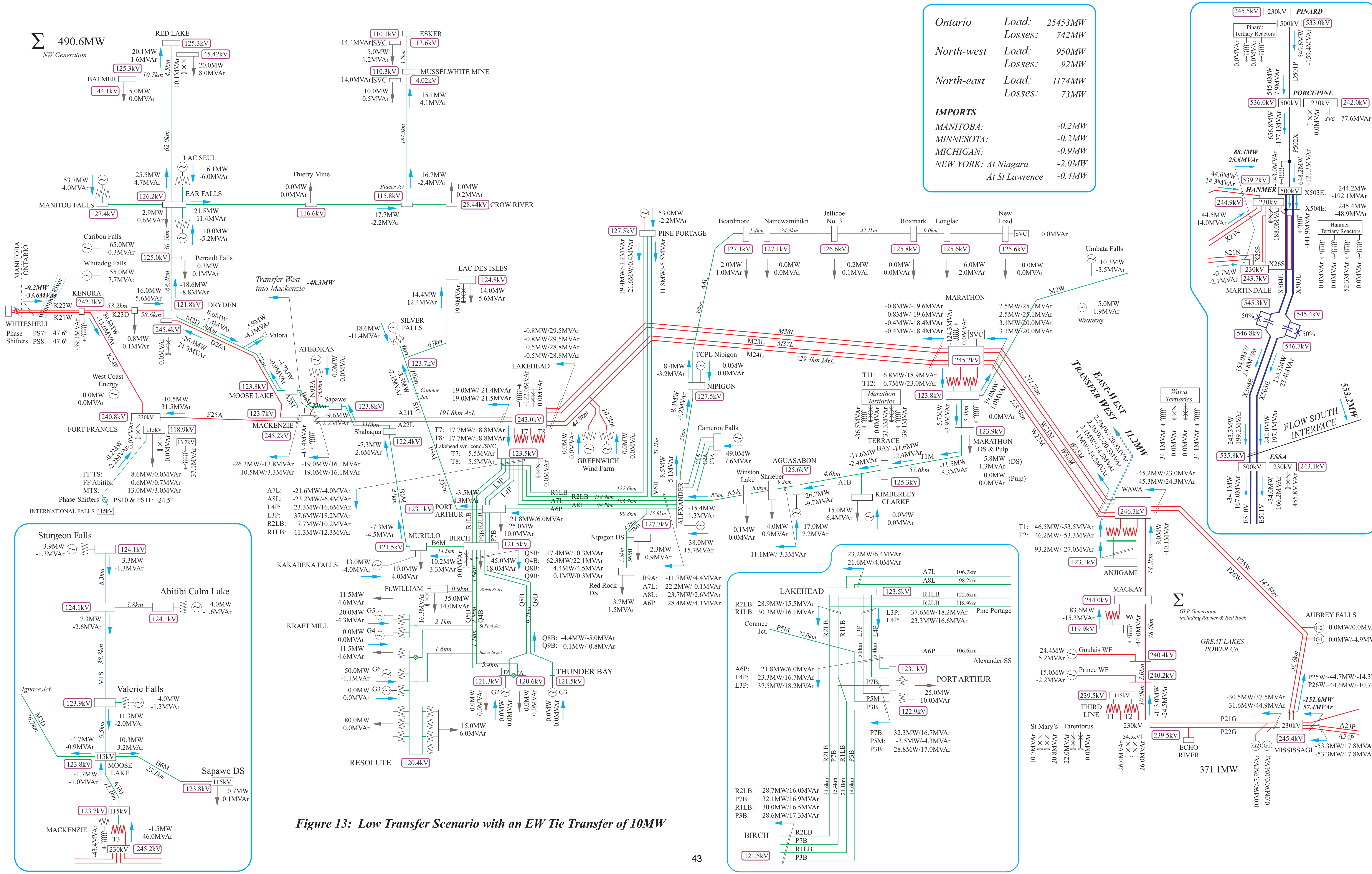

Figure 13: Low Transfer Scenario with an EW Tie Transfer of 10MW

Appendix C: Relay margin analysis

The following figures show some representative results of the relay margin analysis:

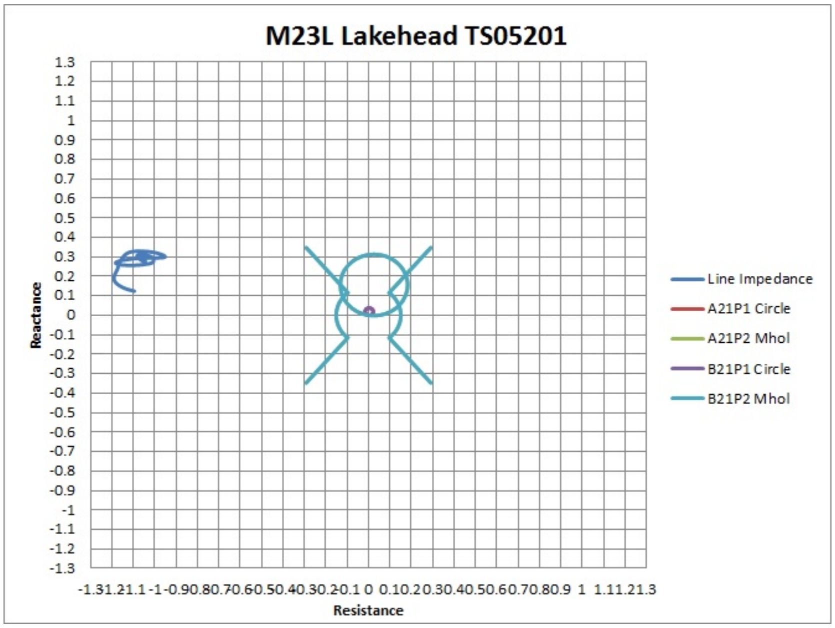

Figure 14: 3 phase fault on M37L at Lakehead TS

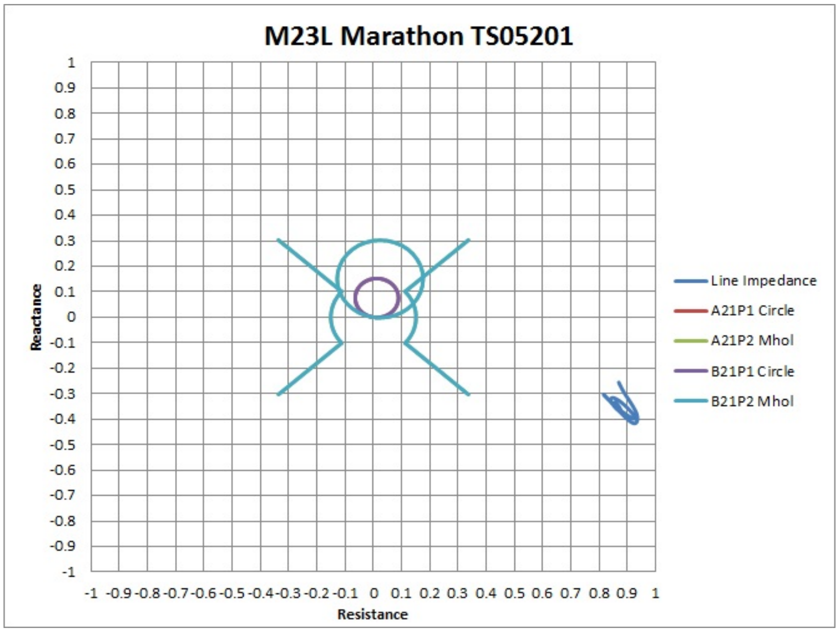

Figure 15: 3 phase fault on M37L at Marathon TS

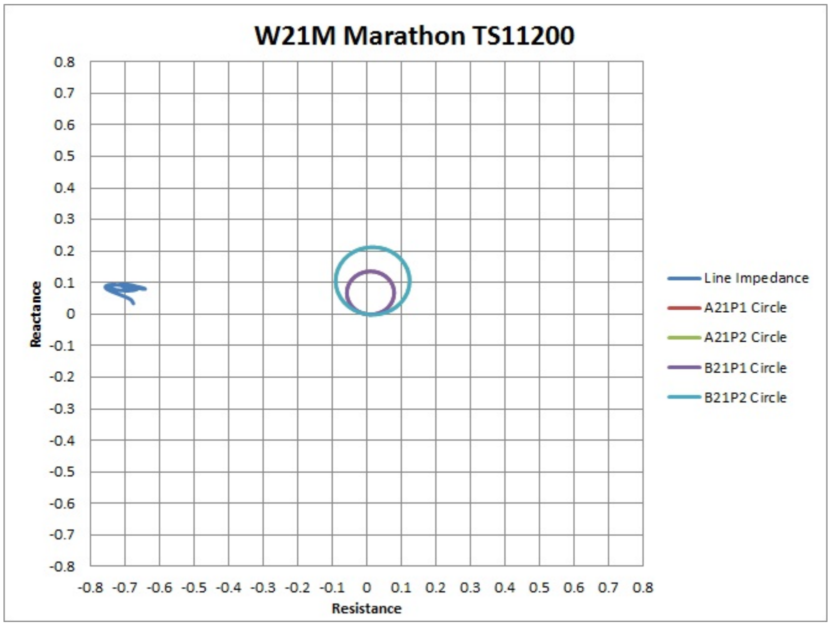

Figure 16: 3 phase fault on W35M at Marathon TS

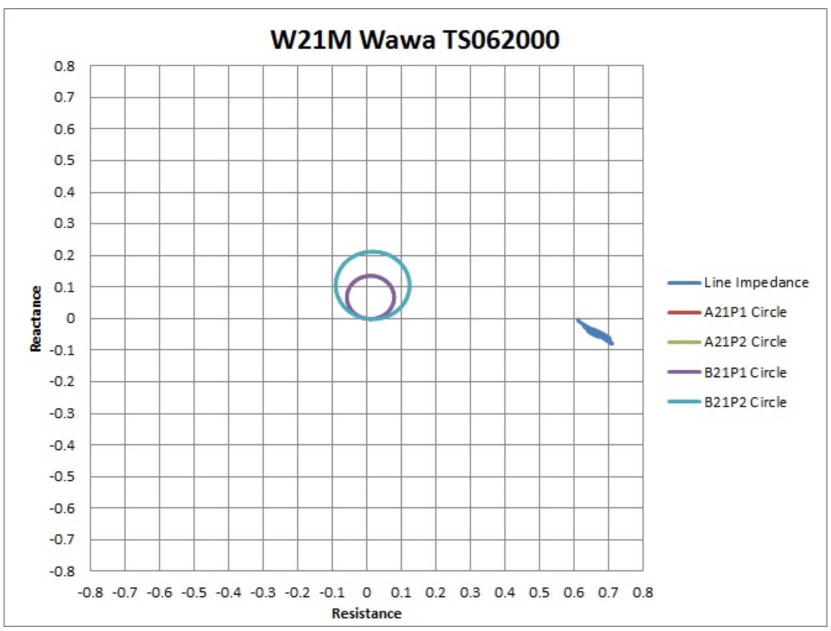

Figure 17: 3 phase fault on W35M at Wawa TS

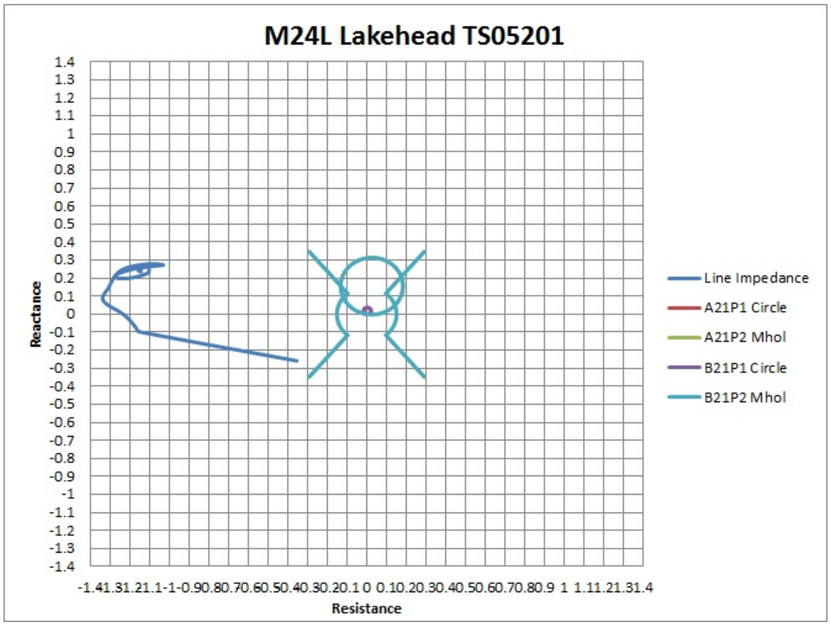

Figure 18: L22L23 breaker failure at Lakehead TS

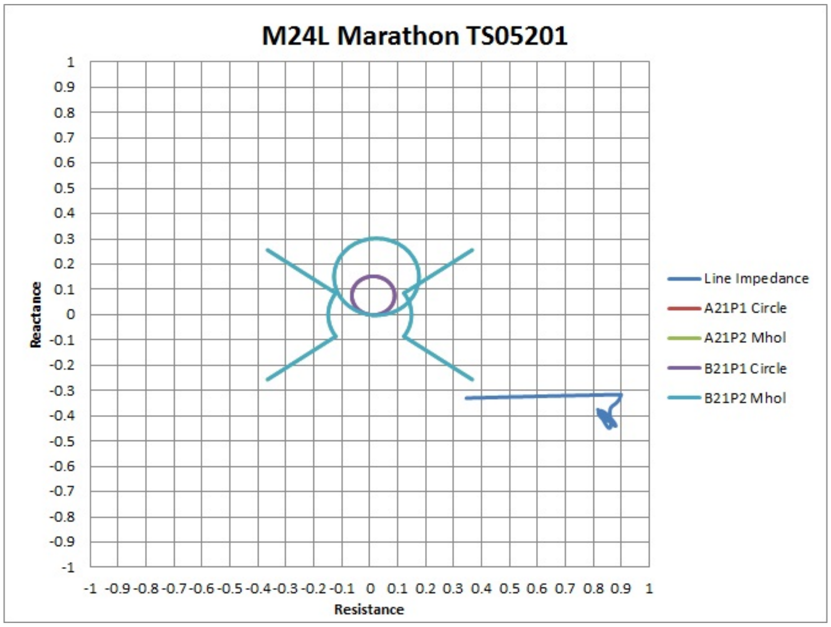

Figure 19: L21L23 breaker failure at Marathon TS

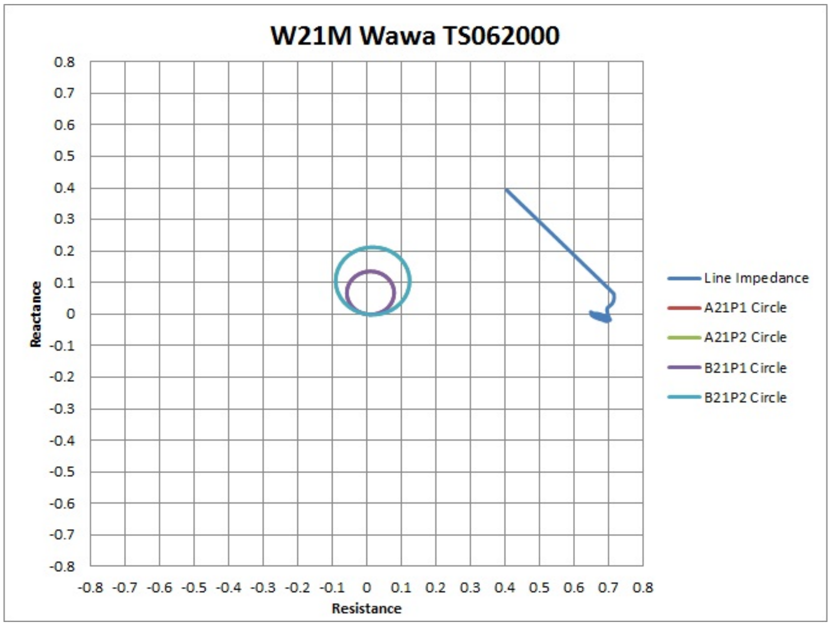

Figure 20: L22L24 breaker failure at Marathon TS

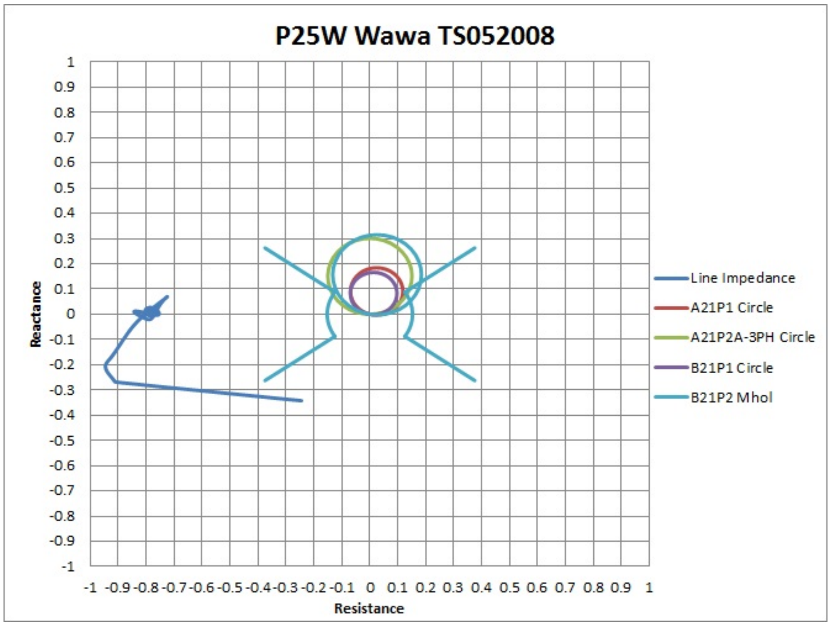

Figure 21: L22L26 breaker failure at Wawa TS

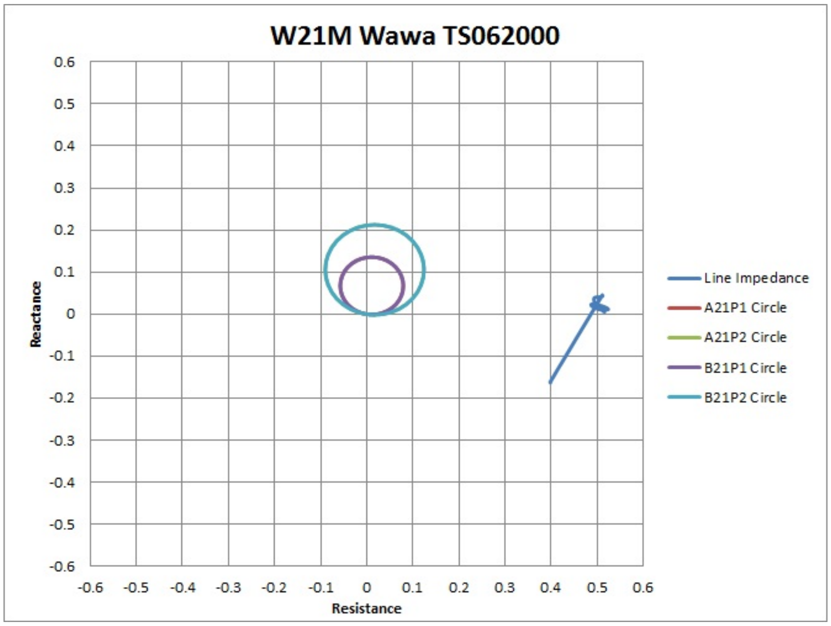

Figure 22: L35L36 breaker failure at Wawa TS

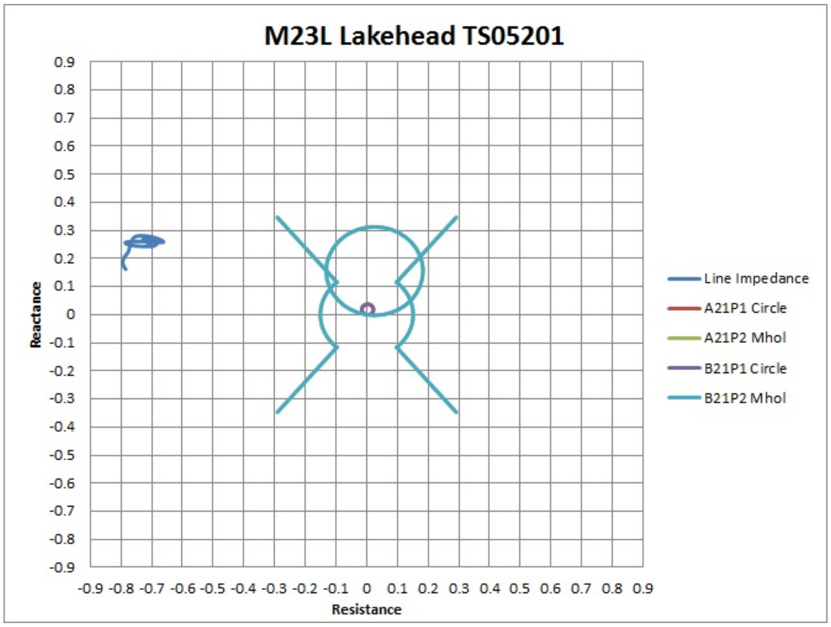

Figure 23: LLG fault on M37L/M38L at Lakehead TS

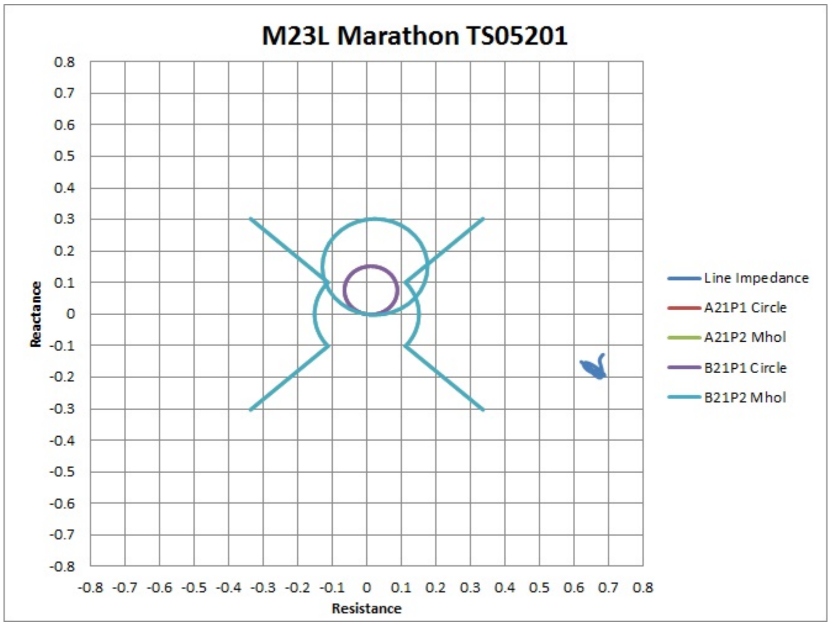

Figure 24: LLG fault on M37L/M38L at Marathon TS

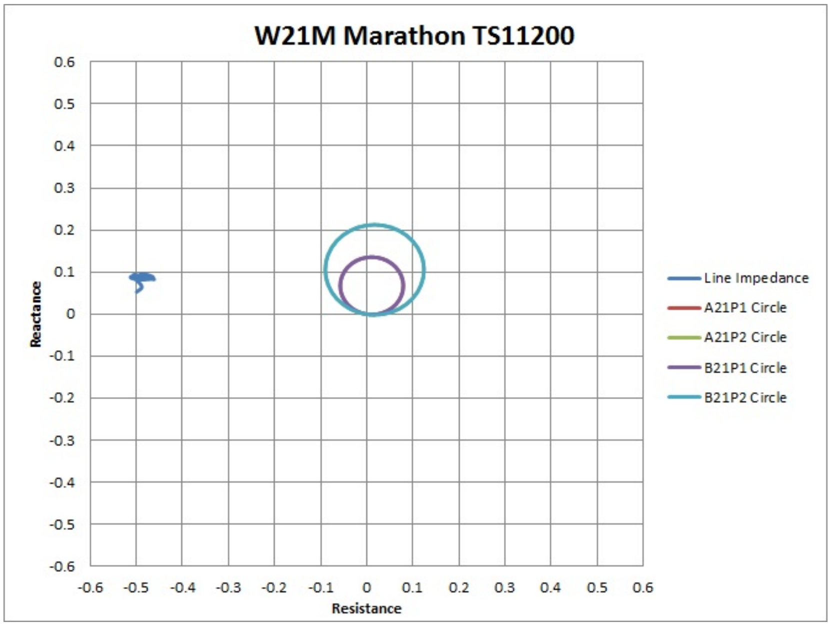

Figure 25: LLG fault on W35M/W36M at Marathon TS

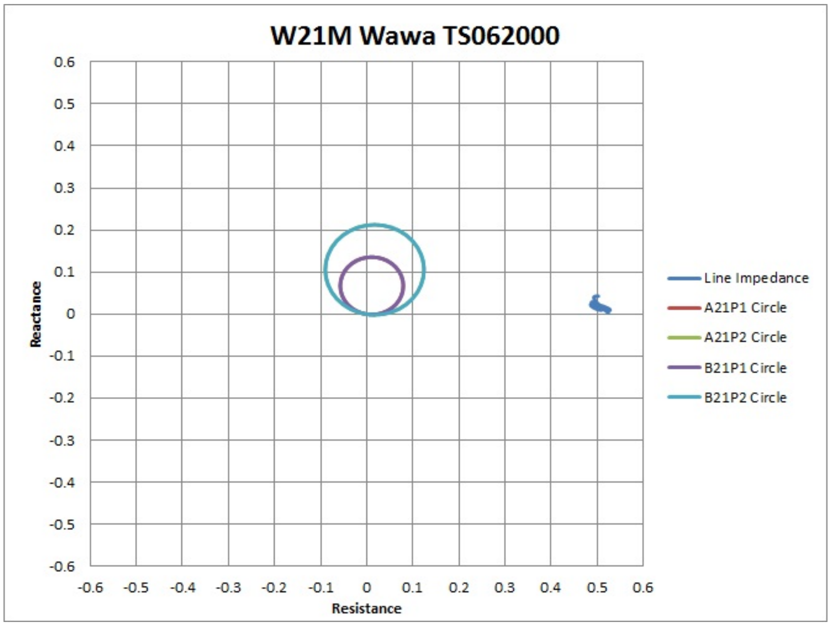

Figure 26: LLG fault on W35M/W36M at Wawa TS

As shown in the previous figures, the relay margins are sufficiently large indicating that the protection settings are acceptable to the IESO.

The following figures show the dynamic voltage response on the main buses in the area following representative faults (note that NW SPS 2 responses, if applicable, were not included):

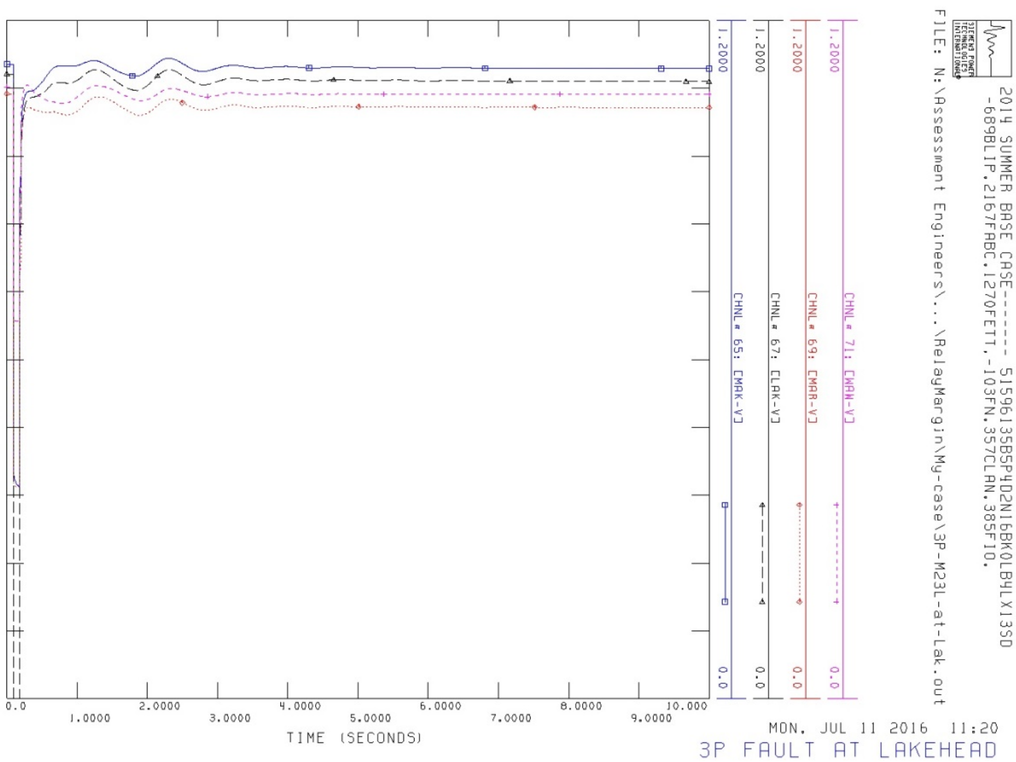

Figure 27: Main bus voltages following a 3P fault near Lakehead TS

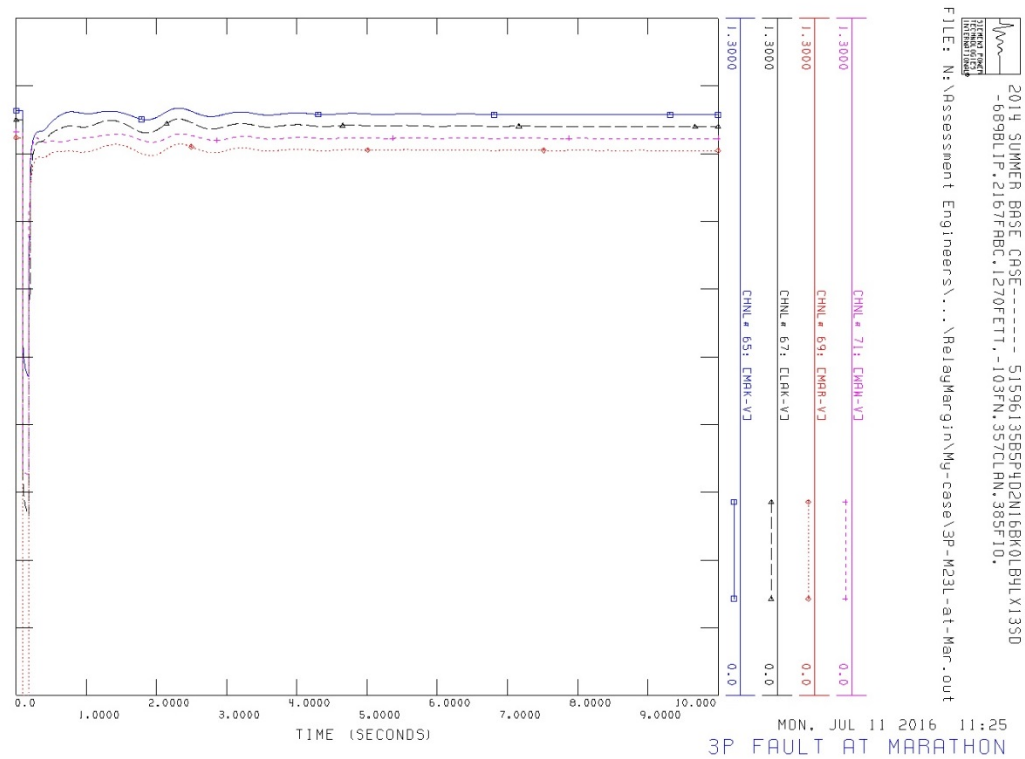

Figure 28: Main bus voltages following a 3P fault near Marathon TS

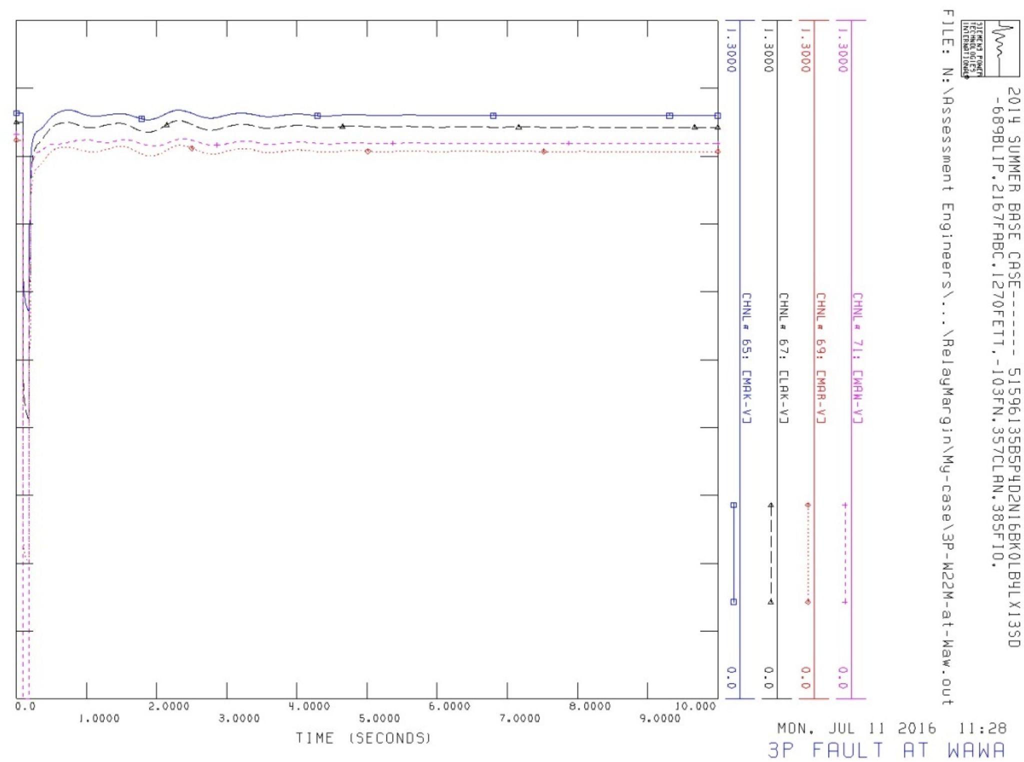

Figure 29: Main bus voltages following a 3P fault near Wawa TS

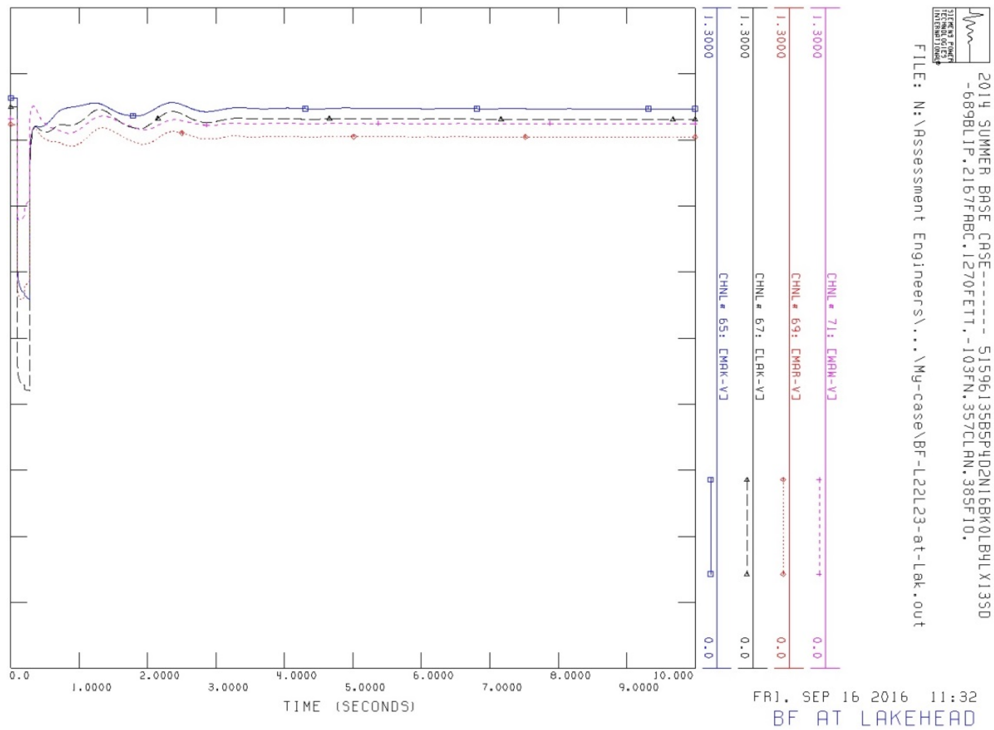

Figure 30: Main bus voltages after an L-G fault and breaker failure at Lakehead TS

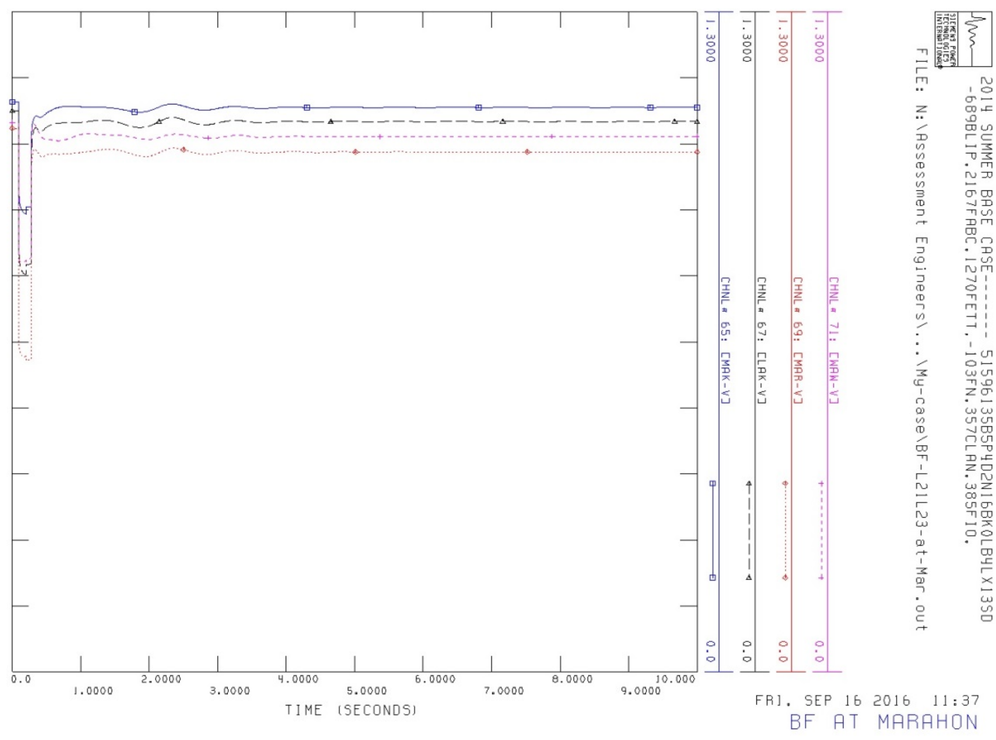

Figure 31: Main bus voltages after an L-G fault and breaker failure at Marathon TS

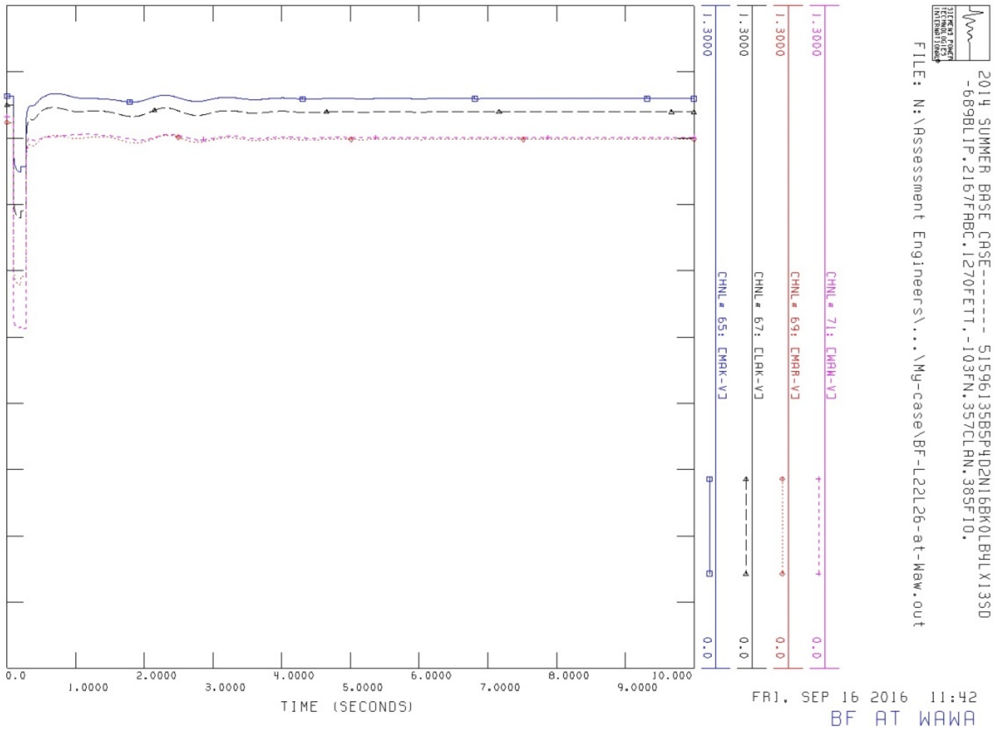

Figure 32: Main bus voltages after an L-G fault and breaker failure at Wawa TS

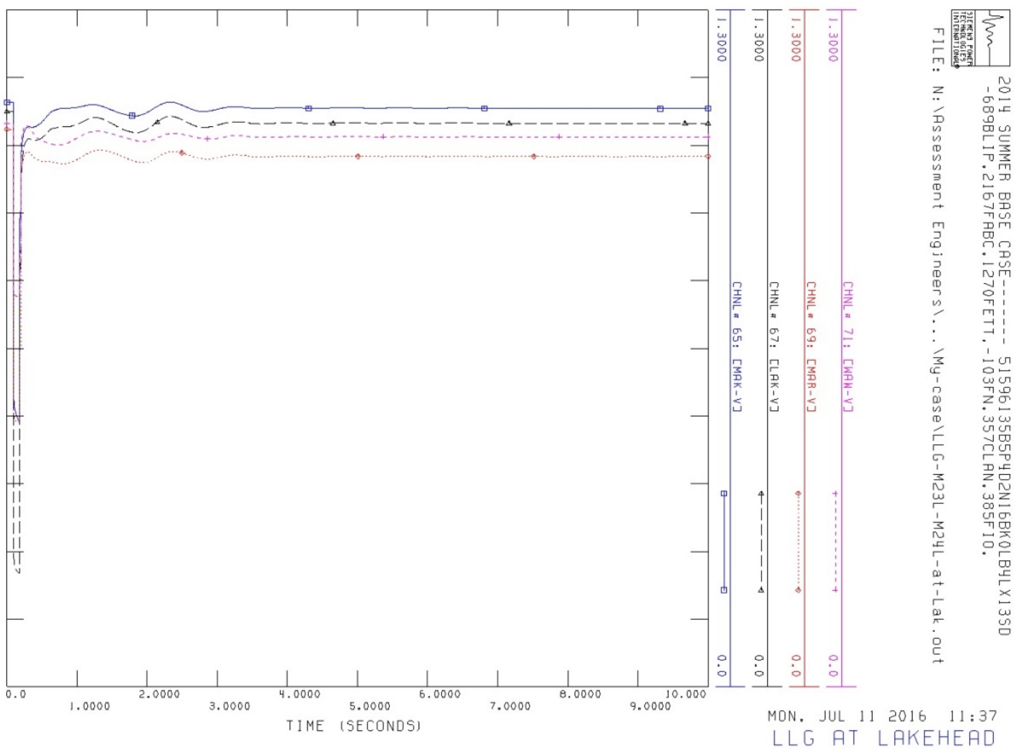

Figure 33: Main bus voltages after an LLG fault at Lakehead TS

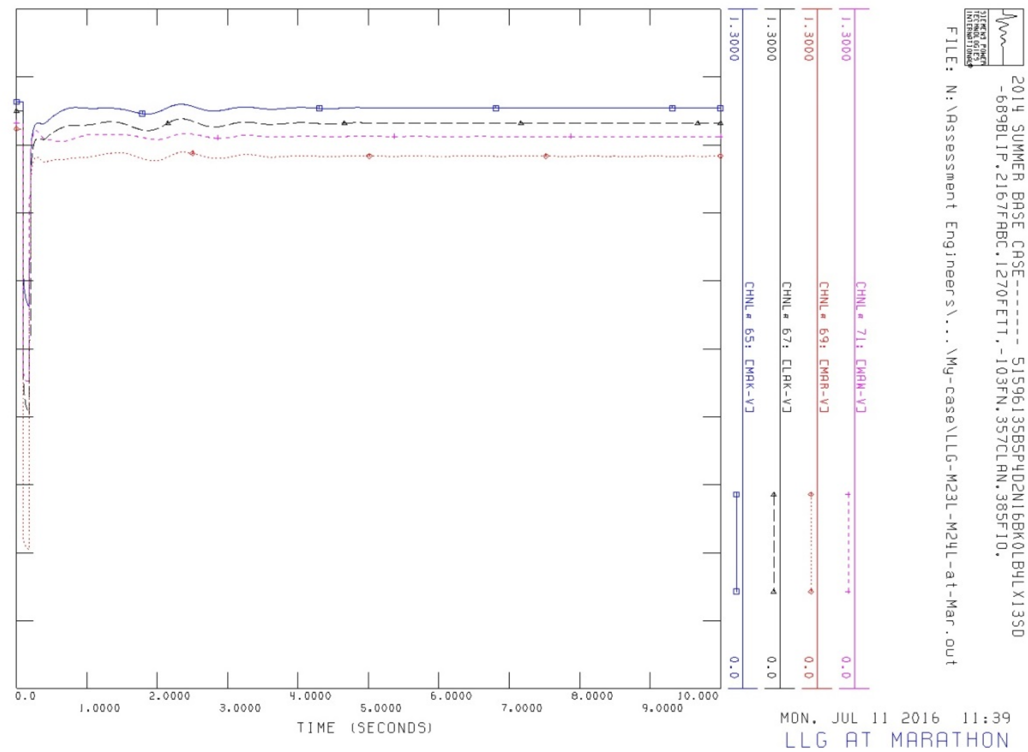

Figure 34: Main bus voltages after an LLG fault at Marathon TS

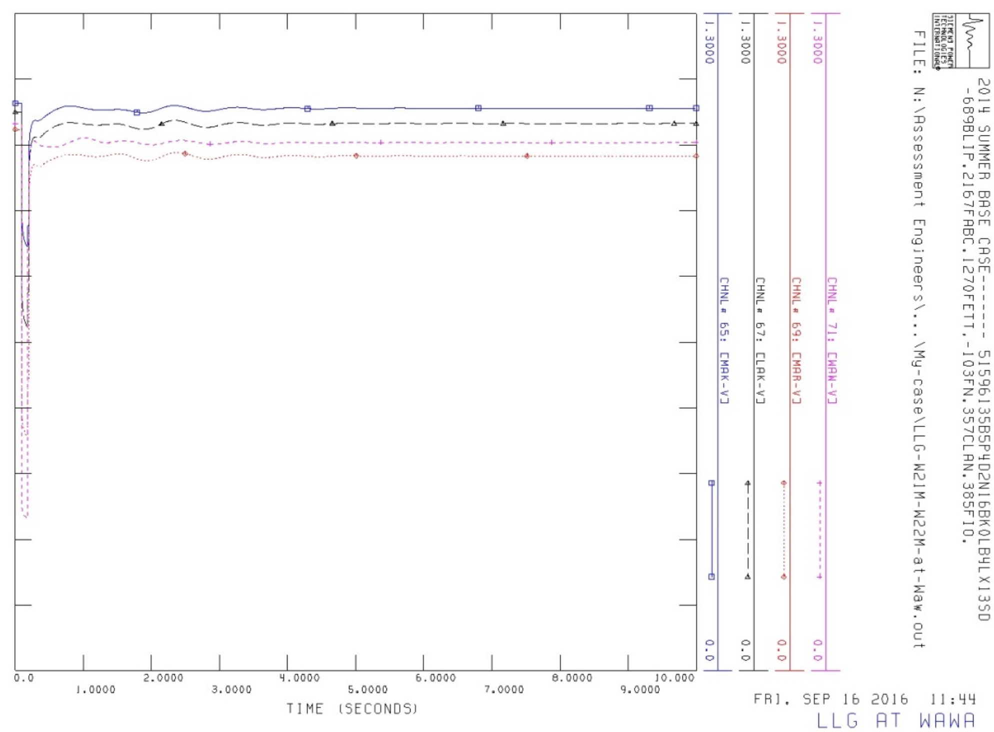

Figure 35: Main bus voltages after an LLG fault at Wawa TS

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REPORT

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Addendum

CAA ID: 2014-514
Project: Ontario 230 kV East-West Tie
Applicant: Upper Canada Transmission Inc.

Connections & Registration Department
Independent Electricity System Operator

Date: December 22, 2016

Document Name	System Impact Assessment Report
Issue	Addendum
Reason for Issue	Updated request for connection assessment by transmitter
Effective Date	December 22, 2016

System Impact Assessment Report

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the proposed connection is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. This report does not in any way constitute an endorsement, agreement, consent or acknowledgment of any kind of the proposed connection for the purposes of obtaining or administering a contract with the IESO for the procurement of electricity supply, generation, demand response, conservation and demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of this transmission system reinforcement proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a system impact assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Executive Summary

Project Description

Upper Canada Transmission Inc. (the "connection applicant") received notification of conditional approval for connection on October 15th 2014 from the IESO for their proposed 230 kV double-circuit transmission line in the Northwest zone of the Ontario transmission system, from Lakehead TS to Marathon TS to Wawa TS (the "project").

Hydro One Networks Inc. (the "transmitter")[1] has since filed a separate request for connection assessment, CAA ID 2016-568, for the associated terminal transformer station modifications at Lakehead TS, Marathon TS and Wawa TS. The project, together with the transmitter's associated terminal transformer station modifications, are intended to provide a targeted westward transfer capability of around 450 MW across the Ontario 230 kV East-West Tie (the "East-West Tie"), which consists of the 230 kV transmission circuits from Wawa TS to Marathon TS to Lakehead TS.

The purpose of this Addendum is to remove the analysis related to the terminal stations modifications from the connection applicant's report and focus it on the new line.

The proposed in service date of the project is December 15, 2020.

Notification of Conditional Approval

This assessment has concluded that the project will not have a material adverse impact on the reliability of the integrated power system. It is therefore recommended that a *Notification of Conditional Approval for Connection* be issued for the project subject to the requirements listed in this report.

Findings

The System Impact Assessment (SIA) has confirmed the following:

(1) The project will not have a materially adverse impact on the reliability of the integrated power system.

(2) Under the North American Electric Reliability Corporation's (NERC) definition of the Bulk Electric System (BES) all elements of the project will be categorized as BES elements.

(3) At the westward transfer levels of about 450 MW studied in this report, the project's equipment will not fall within the Northeast Power Coordinating Council (NPCC) definition of the Bulk Power System (BPS).As presented in the final SIA report for the transmitter's project (CAA_ID 2014-514), it is expected that once the new SVC is installed at Marathon TS and the East-West Tie transfer capability is increased to 650 MW westward, Marathon TS, together with all of the 230 kV circuits that terminate at that station (existing: M23L, M24L, W21M and W22M, and new: M37L, M38L, W35M and W36M) will fall within the NPCC's definition of the BPS.

[1] Where referenced in this report, the "transmitter" applies exclusively to Hydro One and has the meaning given to it by section 1.0.1 (c) of the Transmission System Code. Within the meaning of this section, Upper Canada Transmission is the "neighbouring Ontario transmitter" and is referred to as the "connection applicant" in this report.

Additional assessments will be required, once the model for the future Marathon SVC becomes available, to determine if Lakehead TS, Wawa TS and Mississagi TS and their associated 230 kV circuits will also be classified as BPS.

Connection Requirements

The connection applicant shall satisfy all general requirements listed in section 2 of this report.

– End of Section –

1. Project description

1.1 Introduction

The connection applicant is proposing to build a 230 kV double-circuit transmission line in the Northwest zone of the Ontario transmission system, from Lakehead TS to Marathon TS to Wawa TS with the parameters provided in Table 1 below.

The transmitter has proposed to modify the configuration of the three terminal transformer stations to facilitate the connection of the new lines, as detailed in CAA ID 2016-568.

The project schedule was revised[2] in 2015 and the current proposed in-service date is the end of 2020. In the revised project schedule, the IESO has recommended changes to the connection facilities, including the addition of 230 kV shunt reactors and the postponing of the originally proposed Static Var Compensator (SVC) at Marathon TS to a future date when there is a need to increase the westward transfer capability of the East-West Tie to 650 MW.

The project, as proposed by the connection applicant, together with the associated terminal transformer station modifications proposed by the transmitter, are expected to be adequate for the targeted transfer of 450 MW across the East-West Tie.

Table 1: Proposed line segments lengths

Segment Description	**Segment Length (km)**
Lakehead to Marathon, Reference Route with Pay's Plat Re-Route	232.6
Marathon to Wawa, Pukaskwa & First Nations Re-Routes	211.7

The electrical parameters of the project are presented in Section 3 of this report.

The transmitter has assigned the following designations to the 230 kV circuits comprising the project:

- Circuits M37L and M38L from Lakehead TS to Marathon TS, and
- Circuits W35M and W36M from Marathon TS to Wawa TS.

This nomenclature has been adopted throughout this report.

– End of Section –

[2] Available on Ontario Energy Board's website at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2011-0140&sortd1=rs_dateregistered&rows=200

2. General requirements

The connection applicant and the transmitter shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and Reliability Standards. The following sections highlight some of the general requirements that are applicable to the proposed project.

2.1 Reliability standards

Under the North-American Electric Reliability Corporation's (NERC) Bulk Electric system (BES) definition, all 230 kV elements of this project will be classified as BES.

The connection applicant will need to ensure that the project complies with the applicable NERC reliability standards. To determine the standard requirements that are applicable to this project, the IESO provides a mapping tool titled "NERC Reliability Standard Mapping Tool/Spreadsheet," which can be accessed at the IESO's public website:

http://ieso.ca/imoweb/pubs/ircp/NERC_Reliability_Standards_Mapping_Tool_Spreadsheet.xls.

Note: the connection applicant and/or the transmitter may request an exemption to the application of the BES definition. The procedure for submitting an application for exemption can be found in Market Manual 11.4: "Ontario Bulk Electric System (BES) Exception" at the IESO's website: http://ieso.ca/imoweb/pubs/ircp/rc_OntarioBESException.pdf

At the westward transfer levels of about 450 MW studied in this report, the project's equipment will not fall within the Northeast Power Coordinating Council (NPCC) definition of the Bulk Power System (BPS). As presented in the final SIA report for the transmitter's project (CAA_ID 2014-514), it is expected that once the future SVC is installed at Marathon TS and the East-West Tie transfer capability is increased to 650 MW westward, Marathon TS, together with all of the 230 kV circuits that terminate at that station (existing: M23L, M24L, W21M and W22M, and new: M37L, M38L, W35M and W36M) will fall within the NPCC's definition of the BPS.

Additional assessments will be required, once the model for the future Marathon SVC becomes available, to determine if Lakehead TS, Wawa TS and Mississagi TS and their associated 230 kV circuits will also be classified as BPS.

However, the IESO recommends that any new facilities that the connection applicant is planning to install under this project should be suitable for a future designation of BPS, to ensure that they remain compliant with the applicable NPCC criteria. To determine the standard requirements that are applicable to this project, the IESO provides a mapping tool titled "NPCC Criteria Mapping Spreadsheet," which can be accessed at the IESO's public website: http://ieso.ca/imoweb/pubs/ircp/NPCC%20Criteria_Mapping_Spreadsheet.xls.

The IESO's criteria for determining applicability of NERC reliability standards and NPCC Criteria can be found in the Market Manual 11.1: "Applicability Criteria for Compliance with NERC Reliability Standards and NPCC Criteria" at the IESO's website http://ieso.ca/imoweb/pubs/ircp/IESO_Applicability_Criteria_for_Compliance_with_NERC_Standards_and_NPCC_Criteria.pdf

Compliance with these reliability standards will be monitored and assessed as part of the IESO's Ontario Reliability Compliance Program. For more details about compliance with applicable reliability standards reliability standards, the connection applicant is encouraged to contact orcp@ieso.ca and also visit the following webpage: http://www.ieso.ca/imoweb/ircp/orcp.asp.

Note, the BPS and BES classifications of the IESO-controlled grid will be re-evaluated by the IESO on an annual basis. As the electrical system evolves, any existing BPS or BES classification may change.

2.2 Voltage levels

The connection applicant shall ensure that the project's equipment meets the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource Transmission Assessment Criteria (ORTAC).

2.3 Power system restoration

According to the Market Manual 7.8, which states restoration participant criteria and obligations, the connection applicant is required to be a restoration participant. Details regarding restoration participant requirements will be finalized during the IESO Market Registration process.

2.4 IESO Market Registration process

The connection applicant must initiate and complete the IESO Market Registration process in a timely manner, at least seven months before energization to the IESO-controlled grid and prior to the commencement of any project related outages, in order to obtain IESO final approval for connection.

"As-built" equipment data including any applicable models and data that would be operational, must be provided to the IESO. This includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Market Rules, NPCC and NERC rules. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages.

As part of the IESO Market Registration process, the connection applicant must provide evidence to the IESO, as required under Market Manual 2: Market Administration, Part 2.20: Performance Validation (sections 2, 4 and 5.4), confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Market Registration process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

At the sole discretion of the IESO, performance tests may be required at transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

2.5 Project Status

As per Market Manual 2.10, the connection application will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO. The project status report form can be found on the IESO web site at http://www.ieso.ca/imoweb/pubs/caa/caa_f1399_StatusReport.doc. Failure to comply with project status requirements listed in Market Manual 2.10 will result in the project being withdrawn.

The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Market Manual 2.10. A committed project is a project that has demonstrated to the IESO a high probability of being placed into service.

This project will be deemed committed by the IESO when the connection applicant, as a licensed transmitter, identifies the project in their Plans for New or Modified Facilities Information Submittal Form for 18-Month Outlook (IESO_FORM_1484), or Plans for Retired, New or Modified Facilities Information Submittal Form (IESO_FORM_1494) provided to the IESO as part of its submission for the IESO 18-Month Outlook and other reliability assessments.

– End of Section –

3. Models and Data

3.1 Parameters of transmission circuits

The connection applicant has proposed the following parameters for the project:

Table 2: Positive sequence impedance of the transmission circuits

Segment Description	Complex Circuit Impedance (Ohms)			Circuit Susceptance (Mhos)
M37L and M38L	11.220	+j	108.000	8.252E-04
W35M and W36M	10.211	+j	98.293	7.510E-04

Table 3: Zero sequence impedance of the transmission circuits

Segment Description	Complex Circuit Impedance (Ohms)			Circuit Susceptance (Mhos)
M37L and M38L	73.571	+j	287.100	4.814E-04
W35M and W36M	66.959	+j	261.300	4.381E-04

Table 4: Conductor type and ratings

Category	Value		
Voltage (kV)	250		
Phase conductor size (kcmil)	1192.5		
Phase conductor type (ASC, ACSR, ACSS, ACCR, etc.) [1]	ACSR		
Phase conductor stranding (# of Al strands/ # of Steel strands)	54	19	
Phase conductors per bundle, spacing if more than one (mm)	1	N/A	
Geometry of all phase and sky wires for each tower type (m)	TBD		
Ground resistivity (ohm-meters)	Pending Investigation		
Skywire size (kcmil)	TBD		
Skywire type (Alumoweld, EHS, HS)	(1) OPGW, (1) Alumoweld		
Skywire number if more than one	2		
Winter thermal ratings: Continuous, Long-term, Short-term (A)	1252	1800	N/A
Summer thermal ratings: Continuous, Long-term, Short-term (A)	1236	1564	N/A

3.2 Models of the transmission circuits

The following parameters were used to model the project for the steady state and dynamic studies:

Table 5: Positive Sequence Impedance of the transmission circuits

Circuit	Positive-Sequence Impedance (p.u. V_B = 220 kV, S_B = 100MVA)		
	R	X	B
M37L and M38L	0.023182	0.2231405	0.399387
W35M and W36M	0.021097	0.2030847	0.363494

The following parameters were used to model the project for short circuit studies:

Table 6: Zero Sequence Impedance of the transmission circuits

Circuit	Zero-Sequence Impedance (p.u. V_B = 220 kV, S_B = 100MVA)		
	R	X	B
M37L and M38L	0.152006	0.593182	0.2329734
W35M and W36M	0.138345	0.539876	0.2120356

– End of Section –

4. System Impact Assessment

The potentially adverse impact of the project is limited mainly to:

- the re-distribution of flows on the parallel 115 kV circuits between Lakehead TS and Marathon TS,
- the increase in the voltage levels in the connection area, and
- the increase in the short-circuit levels.

To compensate for the additional reactive output from the project and the subsequent increase in the voltages within the project area, reactive compensation will be required at the terminal transformer stations. The layout of these terminal transformer stations will also influence the ability to achieve the targeted transfer of 450 MW westwards. Both of these aspects are addressed in CAA_ID 2016-568.

This report therefore limits its coverage to the re-distribution of the power flows and the increase in the short circuit levels.

4.1 Standards and Criteria

Reference 2 in Appendix 4.1 of the market rules indicates that under normal conditions the voltage of a nominal 230 kV system is maintained between 220 kV and a maximum continuous value of 250 kV.

Additionally, sections 4.2 and 4.3 of IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) specify that:

- Under pre-contingency conditions, with all facilities in service, the nominal 230 kV voltage levels are between 220 kV and 250 kV; and
- System voltage changes following a contingency are between 207 kV and 250 kV for the nominal 230 kV system.

It should be noted that voltage outside of this range can occur for very short periods of time during transients or following the switching in or out of reactive control devices and transformers.

4.2 Study Assumptions

The main study assumptions are listed below:

Generation Assumptions:

- In the Northwest transmission zone, the output from the existing hydroelectric facilities was set to 342 MW, representing approximately 40% of their peak output. This would be in the range expected from these hydroelectric facilities during a drought year. A further contribution of 77 MW was also assumed to be available from the existing thermal facilities in this zone, resulting in a total zone generation of 419 MW**.** Atikokan GS and Thunder Bay GS biomass fired thermal facilities and the Greenwich WGS were assumed to be out-of-service.
- In the Northeast transmission zone, the output from the existing hydroelectric facilities was set to 1397 MW, representing approximately 47% of their peak output. This would be in the range expected from these hydroelectric facilities during a drought year. The existing thermal generation in the area was assumed to contribute a further 406 MW (around 50% of their maximum), wind at 70 MW (20% of its maximum) and solar at 41 MW (77% of its maximum) for a total generation in the zone of 1915 MW.
- The dispatch of generation in southern Ontario has negligible impact on the project and as such a generic dispatch corresponding to peak summer conditions was used.

Load Assumptions:

- In the Northwest transmission zone, the peak load of about 797 MW was selected to reflect the current long term forecast under the "Low Growth" scenario of the IESO's need update report[3] dated December 15, 2015. This load level would give a peak demand of approximately 876 MW once the transmission losses of approximately 78 MW have been factored in.
- The load in Northeast was set to 1150 MW which yields a peak demand of approximately 1240 MW once the transmission losses of approximately 90 MW were factored in.
- Demand in southern Ontario has negligible impact on the project and as such a generic summer peak demand was used.

Transfers on the East-West Tie and on the Sudbury Flow West Interface

The demand and generation assumptions in the Northwest and Northeast transmission zones resulted in:

- A Sudbury Flow West (SFW) transfer of 317 MW;
- A Flow into Wawa TS of 468 MW;
- An East-West Tie transfer of 463 MW westwards;
- A Flow from Marathon TS to Lakehead TS of 427 MW; and
- A Flow from Lakehead TS to MacKenzie TS of 127 MW.

The phase-angle-regulators on the interconnections with Minnesota and Manitoba were adjusted to achieve zero transfers.

4.3 Re-distribution of flows

Upon completion of the project, there will be four 230 kV circuits between Marathon TS and Lakehead TS (the new circuits M37L and M38L, together with the existing circuits M23L and M24L) and these will be operated in parallel with the series-connected 115 kV circuits T1M, A1B and A5A, between Marathon TS and Alexander SS.

Pre-contingency

With all transmission circuits in-service, and with an increased East-West Tie transfer of 450 MW, the reduced impedance presented by the four 230kV circuits will result in lower transfers via the 115kV path than occur presently, as shown in the following table.

[3] This report is available on Ontario Energy Board's website at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=eb-2011-0140&sortd1=rs_dateregistered&rows=200

Table 7: Re-distribution of flow between 230 kV and 115 kV parallel systems

Power flows:	M23L	M24L	M37L	M38L	T1M	East-West Tie Transfer
Before project (MW)	132.1	132.0	-	-	49.6	**350MW**
After project (MW)	94.1	94.1	99.9	99.9	39.3	**450MW**

Post-contingency

Following a double-circuit contingency involving the new 230 kV line, the post-contingency flows, with an enhanced East-West Tie transfer of 450 MW, will be as shown in Table 8.

Table 8: Post-contingency flows on the Marathon to Lakehead Corridor

Power flows:	M23L	M24L	M37L	M38L	T1M	East-West Tie Transfer
Post-contingency	187.9	187.8	***Out-of-Service***		68.6	**450MW**

The flow via the 115 kV series-connected path that operates in parallel with the 230 kV corridor will remain within the rating of these circuits.

4.4 Fault Level Analysis

A fault level analysis was conducted by the transmitter on behalf of the IESO to identify the impact of the project on local short circuit levels. Changes in local short circuit levels as a result of incorporating the project are very small and not expected to have adverse impact on the reliability of the integrated power system. The tests were performed assuming all existing and committed generators in service (including Atikokan and Thunder Bay).

Table 9: Fault level before and after completion of the project

		Lowest rated breaker		Before the project				After the project			
				Three phase fault		Line to ground fault		Three phase fault		Line to ground fault	
Station Name	Bus	Symm	Asym	Symm	Asym	Symm	Asym	Symm	Asym	Symm	Asym
	kV	kA	kA	kA	kA	kA	kA	kA	kA	kA	kA
MacKenzie TS	220	38.5	46.2	6.319	8.008	6.515	8.455	6.418	8.124	6.593	8.542
	115	31.5	37.8	5.940	7.240	7.128	9.090	5.980	7.281	7.167	9.132
Lakehead TS	220	38.5	46.2	7.324	9.126	7.523	9.861	8.184	10.156	8.353	10.886
	115	31.0	34.1	16.895	18.926	18.714	21.905	17.892	20.084	19.749	23.143
Marathon TS	220	38.5	46.2	5.236	5.815	5.072	5.836	6.988	7.994	6.737	7.915
	115	34.7	41.6	7.065	7.523	8.318	9.082	8.109	8.941	9.532	10.773
Wawa TS	220	38.5	46.2	6.818	7.815	6.127	7.710	7.671	8.837	6.943	8.745
	115	20.7	22.7	7.874	8.777	9.456	11.088	8.299	9.342	9.977	11.826
Terrace Bay SS	115	40.0	48.0	4.723	5.703	3.702	4.341	4.81	5.793	3.740	4.378
Aguasabon SS	115	40.0	48.0	4.561	5.284	3.955	4.929	4.633	5.356	3.992	4.969

The highest expected short circuit levels, both 230 kV and 115 kV are shown to be within the lowest rated breaker capability at all stations in the area.

Table 10 shows the changes in fault level after the project:

Table 10: Fault level changes following the completion of the project

Station Name	Voltage (kV)	Three phase fault		Line to ground fault	
		Symmetrical (kA)	Asymmetrical (kA)	Symmetrical (kA)	Asymmetrical (kA)
MacKenzie TS	220	0.099	0.116	0.078	0.087
	115	0.040	0.041	0.039	0.042
Lakehead TS	220	0.860	1.030	0.830	1.025
	115	0.997	1.158	1.035	1.238
Marathon TS	220	1.752	2.179	1.665	2.079
	115	1.044	1.418	1.214	1.691
Wawa TS	220	0.853	1.022	0.816	1.035
	115	0.425	0.565	0.521	0.738
Terrace Bay	115	0.087	0.090	0.038	0.037
Aguasabon	115	0.072	0.072	0.037	0.040

This assessment has concluded that the project will not have a material adverse impact on the reliability of the integrated power system

– End of Section –

Appendix A: Power flow scenarios used in this study

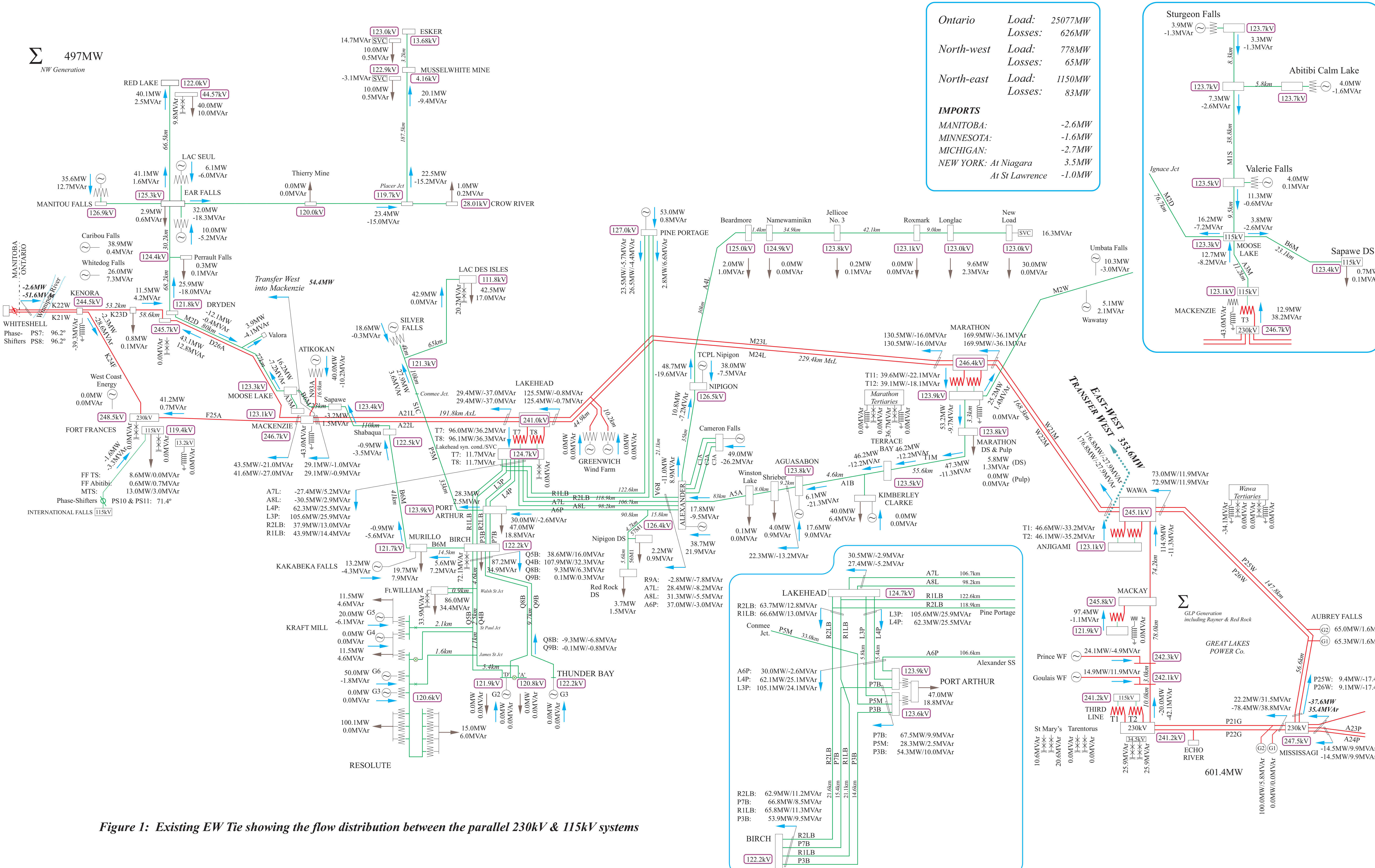

Figure 1: Existing EW Tie showing the flow distribution between the parallel 230kV & 115kV systems

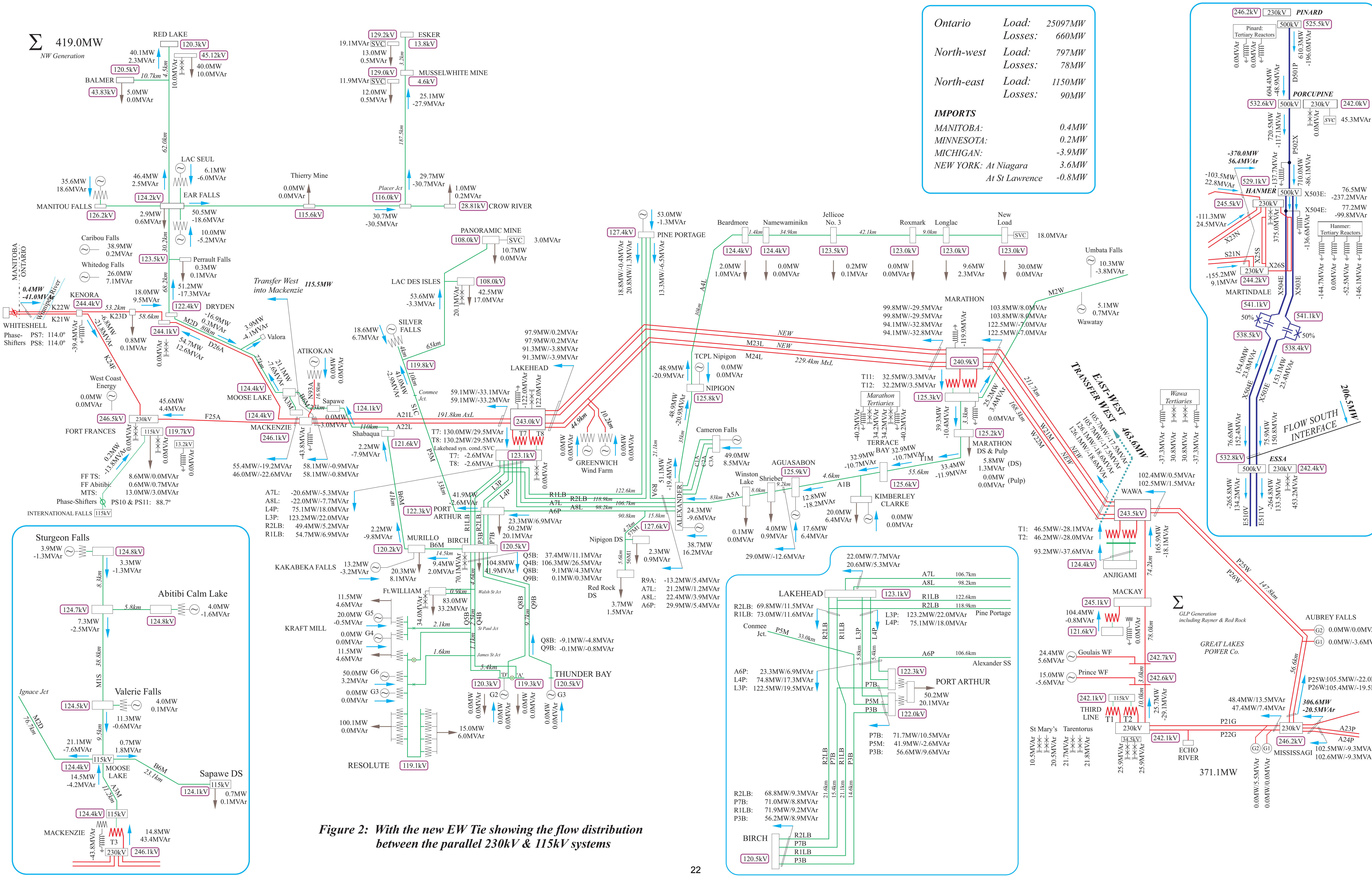

Figure 2: With the new EW Tie showing the flow distribution between the parallel 230kV & 115kV systems

Customer Impact Assessment

Please refer to Attachment 1 for the Customer Impact Assessment prepared by Hydro One.

483 Bay Street
Toronto, Ontario
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CUSTOMER IMPACT ASSESSMENT

EAST-WEST TIE EXPANSION

Plan/Project #: **AR 19927**

Revision: **Final**

Date: **January 16, 2017**

Issued by: **Transmission Planning (North&West) Department**
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DISCLAIMER

This Customer Impact Assessment was prepared based on preliminary information available about the proposed *East-West Tie Expansion* project, consisting of construction of a 230 kV double-circuit, overhead transmission line between Wawa Transformer Station (TS), Marathon TS and Lakehead TS and the associated facilities at these three stations. This report is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have, including those needed for the review of the connection and for any possible application for Leave to Construct. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in this Customer Impact Assessment. The results of this Customer Impact Assessment and the estimate of the outage requirements are subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements. The fault levels computed as part of this Customer Impact Assessment are meant to assess current conditions in the study horizon and are not intended to be for the purposes of sizing equipment or making other project design decisions. Many other factors beyond the existing fault levels go into project design decisions.

Hydro One Networks Inc. shall not be liable, whether in contract, tort or any other theory of liability, to any person who uses the results of the Customer Impact Assessment under any circumstances whatsoever for any damages arising out of such use unless such liability is created under some other contractual obligation between Hydro One Networks Inc. and such person.

Contents

Executive Summary

The East-West Tie expansion was identified as one of the priority transmission projects in the government of Ontario's 2010 Long-Term Energy Plan and was included in the 2013 Long-Term Energy Plan. The Minister of Energy asked the Ontario Energy Board (OEB) to designate a transmission company to develop the new East-West Tie transmission lines. In 2013 the OEB selected Upper Canada Transmission Inc. (UCT) as the transmitter to carry out the development work for the new 230 kV double-circuit lines that will be connected between Hydro One's existing Wawa Transmission Station (TS), Marathon TS and Lakehead TS, located near the cities of Wawa, Marathon and Thunder Bay, respectively.

In 2014 UCT applied for the SIA for the new East-West Tie project with the expected in-service date of 2018-Q1. The Independent Electricity System Operator (IESO) issued the SIA report CAA 2014-514, "Ontario 230 kV East-West Tie", dated Oct. 15, 2014. Hydro One performed the Customer Impact Assessment for the project and issued the final CIA report, dated October 29, 2014, following the review of the draft CIA report by the customers within the study area of the project.

In 2015, the project schedule was revised[1] and the current proposed in-service date is the end of 2020. More importantly, since 2014, the IESO has recommended changes to the connection facilities, including addition of 230 kV shunt reactors. The IESO has also recommended postponing the SVC at Marathon TS and the upgrade of Marathon-Alexander 115 kV circuits to a later date when 650 MW East-West transfer capability is required. The revised connection and station facilities, without the SVC at Marathon TS, will provide 450 MW East-West transfer capability.

The project now consists of:

- Construction of new 230 kV double-circuit transmission lines, about 440 km in total length, between Wawa TS, Marathon TS and Lakehead TS, with one Optical Ground Wire and one regular shield wire
- Reconfiguration of the above three stations and addition of breakers and switches for connection of the new circuits and re-termination of some of the existing circuits
- Addition of the following reactive power sources:
    - Two new 230 kV shunt reactors, rated at 65 MVAr each, at Marathon TS
    - A new 230 kV shunt reactor, rated at 125 MVAr, at Lakehead TS
    - A new shunt capacitor bank, rated at 125 MVAr, at Lakehead TS
- Revision of the new Northwest Special Protection Scheme (NW SPS 2) for the new and reconfigured transmission lines and shunt capacitors and reactors, as well as addition of new contingencies at Marathon TS and Wawa TS

UCT (under NextBridge tradename) is developing the new 230 kV transmission lines, including the route selection and design of the new lines. Hydro One will perform the other aspects of the project listed above.

[1] For more information (IESO Update Report, etc.), see Ontario Energy Board's website at: http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/East-West+Transmission+Tie+Line

The IESO has carried out new System Impact Assessment (SIA) studies to assess the impact of the revised project on voltage performance, thermal loading and short-circuit currents in the area. The results and findings of the studies are reported in an addendum to the 2014 SIA (CAA ID 2014-514, "Ontario 230 kV East-West Tie") and a new SIA report CAA ID 2016-568, "Ontario 230 kV East-West Tie Connections". These reports confirm that,

- The revised project provides 450 MW transfer capability between Northeast and Northwest regions of Ontario,
- Voltage performance in the area remains within the Market Rules requirements,
- Thermal loading of the facilities remains within their ratings, and
- The impact of the project on short-circuit currents is relatively small, and
- Transient response of the system (in particular, relay margin assessment) is acceptable.

This Customer Impact Assessment (CIA) report describes the potential impact of the new (revised) East-West Tie project on short circuit current, voltage and power supply reliability of the customers in the affected area. The findings of this CIA are:

1. The project has relatively small impact on Short-Circuit Levels in the area since it does not significantly reduce the net (equivalent) impedance between the affected stations and the sources of short-circuit current (i.e., generators).

2. The project has no adverse impact on voltage performance in the area. The addition of new reactive power sources and NW SPS 2 will allow for effective control of the voltages within the planning and operating criteria under various contingencies and outage conditions. Switching of the new shunt reactors and capacitor bank will not cause voltage variations beyond the applicable criteria.

3. The project will improve the customer power supply reliability in the area. Addition of the new East-West Tie transmission line, reactive power sources and NW SPS 2 ensure supply adequacy and reliability in Northwest under local generation shortages and various outages and contingencies.

CUSTOMER IMPACT ASSESSMENT

EAST-WEST TIE EXPANSION

1. Introduction

The Minister of Energy included the East West Tie Expansion project in the 2010 Long-Term Energy Plan and 2013 Long-Term Energy Plan. The IESO, in its December'2015 Update Report to the OEB stated that:

> "The E-W Tie expansion project continues to be the IESO's recommended alternative to maintain a reliable and cost effective supply of electricity to the Northwest for the long term."

The OEB has selected Upper Canada Transmission Inc. (operating under the Trade name "NextBridge") as the transmitter to carry out the development work for the proposed East-West Tie transmission line, consisting of 230 kV double-circuit lines along the north shore of Lake Superior, connecting to Wawa Transformer Station (TS), Marathon TS and Lakehead TS. The initial plan (in 2014) was according to the IESO's Feasibility Study, which targeted 650 MW transfer capability between Northeast and Northwest regions of Ontario.

In 2014 the IESO issued the SIA report CAA 2014-514, "Ontario 230 kV East-West Tie", dated Oct. 15, 2014, for the project. Hydro One performed the Customer Impact Assessment for the project and, following the review of the draft CIA report by the customers within the study area, issued the final CIA report, dated October 29, 2014.

In the 2015 Update Report, the IESO has recommended "a targeted in-service date by the end of 2020" for the project, with revised station facilities and configurations that will provide 450 MW transfer capability between Northeast and Northwest regions of Ontario. In the future, the East-West transfer capability can be increased to 650 MW by the installation of an SVC at Marathon TS and upgrading sections of the Marathon-Alexander 115 kV circuits.

As part of the Connection Assessment and Approval (CAA) process, the IESO has conducted the System Impact Assessment (SIA) for the revised project and issued an addendum to the 2014 SIA (CAA ID 2014-514, "Ontario 230 kV East-West Tie"[2]) and a new SIA report CAA ID 2016-568, "Ontario 230 kV East-West Tie Connections"[3]. These reports confirm that with the proposed facilities, under the expected operating conditions (i.e., up to 450 MW East-West transfer), voltage performance in the area remain within the Market Rules requirements, the thermal loading of the facilities remain within their ratings, and the impact on short-circuit currents is relatively small.

This Customer Impact Assessment (**CIA**), carried out by Hydro One in accordance with the requirements of the OEB Transmission System Code, reviews the impact of the project on the existing customers in the area. Table 1 lists the transmission customers in the area from east of Wawa to west of Thunder Bay.

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[2] https://ieso-public.sharepoint.com/Documents/caa/CAA_2014-514_Addendum_1.pdf

[3] https://ieso-public.sharepoint.com/Documents/caa/CAA_2016-568_Final_Report.pdf

Table 1: Transmission Customers in the Project's Area

Stations / Junctions	Circuits	Customers
Mississagi TS – 230 kV	P21G, P22G	• Brookfield Renewable Power
Aubrey Falls – 230 kV	P25W, P26W	• Mississagi Power Trust
Chapleau Jct – 115 kV Chapleau DS – 115 kV	W2C	• Chapleau Public Utilities Corporation • Tembec Industries Inc. • Hydro One Distribution
Greenwich Jct – 230 kV	M23L, M24L	• Greenwich Windfarm LP
Pic Jct – 115 kV Marathon DS Jct - 115 kV	T1M	• Marathon Pulp Inc. • Hydro One Distribution
Terrace Bay SS - 115 kV AV Terrace Bay Jct – 115 kV	T1M, A1B	• AV Terrace Bay Inc.
Aguasabon SS – 115 kV	A1B, A5A	• Ontario Power Generation Inc. • Hydro One Distribution
Schreiber Jct – 115 kV	A5A	• Hydro One Distribution
Minnova Jct – 115 kV	A5A	• FQM (Akubra) Inc.
Pic DS - 115 kV	M2W	• Hydro One Distribution
Manitouwadge Jct - 115 kV Manitouwadge TS - 115 kV	M2W	• Kagiano Power • Haavaldsrud Timber Co. Ltd. • Glencore Canada Corporation • Hydro One Distribution
Black River Junction - 115 kV	M2W	• Cpot Title Corp
Umbata Falls Jct - 115 kV	M2W	• Umbata Falls LP
Hemlo Mine Jct - 115 kV	M2W	• Williams Operating Corp
Animki Jct – 115 kV	M2W	• Pic Mobert Hydro Inc.
White River DS - 115 kV	M2W	• Hydro One Distribution
Birch TS – 115 kV		• Thunder Bay Hydro
Port Arthur TS #1 – 115 kV		• Thunder Bay Hydro • Lac Des Iles Mines Ltd. • Ontario Power Generation Inc. • Hydro One Distribution
Alexander SS – 115 kV		• Ontario Power Generation Inc.
Pine Portage SS – 115 kV		• Ontario Power Generation Inc.
Nipigon Jct – 115 kV	56M1, 57M1	• Hydro One Distribution
Red Rock Jct – 115 kV	56M1	• Red Rock Mill Inc. • Hydro One Distribution
A.P. Nipigon Jct – 115 kV	A4L	• Atlantic Power LP
Beardmore Jct – 115 kV	A4L	• The Power Limited Partnership • Hydro One Distribution
Jellicoe DS #3 Jct – 115 kV	A4L	• Hydro One Distribution
Roxmark Jct – 115 kV	A4L	• Roxmark Mine Limited
Long Lac TS – 115 kV, 44 kV	A4L	• Hydro One Distribution
Murillo Jct – 115 kV	B6M	• Ontario Power Generation Inc. • Hydro One Distribution
Shabaqua Jct – 115 kV Sapawe Jct – 115 kV	B6M	• Hydro One Distribution

Stations / Junctions	Circuits	Customers
Fort William TS – 115 kV, 25 kV		• Thunder Bay Hydro
St. Paul Jct – 115 kV	Q5B	• Resolute FP Canada Inc.
James St. Jct – 115 kV	Q4B, Q5B	• Resolute FP Canada Inc.
Thunder Bay SS – 115 kV		• Resolute FP Canada Inc. • Ontario Power Generation Inc.
Moose Lake TS – 44 kV		• Atikokan Hydro Inc.

The Great Lakes Power Transmission (GLPT) system is connected to the grid at Hydro One's Wawa TS and Mississagi TS. The GLPT's connected customers are not listed in the above table.

2. Proposed Facilities

The proposed new line and station facilities consist of the following (see also Fig 1:6)

- **New East-West Tie line**

  New 230 kV double-circuit overhead transmission lines, about 440 km in total length, will be connected between Wawa TS, Marathon TS and Lakehead TS. The new lines will consist of:
  - Single 1192.5 kcmil ACSR conductor per phase
  - One Optical Ground Wire
  - One Alumoweld skywire

- **Station Reconfigurations and New facilities**

  Wawa TS, Marathon TS and Lakehead TS will be reconfigured, with the addition of new bus work and new breakers/ switches, for connection of the new circuits, re-termination of some of the existing circuits, and addition of the following reactive power sources:
  - Two 230 kV shunt reactors, rated at 65 MVAr each, at Marathon TS
  - A 230 kV shunt reactor, rated at 125 MVAr, at Lakehead TS
  - A 230 kV shunt capacitor bank, rated at 125 MVAr, at Lakehead TS

- **Revising Northwest SPS**

  The new Northwest Special Protection Scheme (NW SPS 2), which is expected to be completed before the end of 2016, will be revised according to the new station configurations and new facilities, as well as addition of new contingencies and actions for the existing facilities. The revisions to NW SPS 2 include:

  a. Add 10 new single and double contingencies (new East-West Tie circuits and existing circuits east/south of Wawa TS):
     - W35M, W36M and W36M+W36M
     - M37L, M38L and M37L+M38L
     - P25W, P26W and P25W+P26W
     - W23K

  b. Remove 4 Marathon breaker failure contingencies

c. Remove 4 Lakehead breaker failure contingencies
d. Add 2 new contingencies "Lakehead Reactor R1" and "Lakehead Capacitor SC21"
e. Replace 2 Lakehead transformer (T7 and T8) contingencies with one "Lakehead T7 OR T8" contingency (i.e., trip of one of the two transformers)
f. Add 2 new transformer contingencies "Marathon T11 OR T12" and "Wawa T1 OR T2" (i.e., trip of one of the two transformers at each station)
g. Add 5 new actions to,
    - Trip Marathon 230 kV reactor R3
    - Trip Marathon 230 kV reactor R4
    - Trip Lakehead 230 kV reactor R1
    - Trip Lakehead 230 kV capacitor SC21
    - Trip Lakehead 115 kV capacitor SC11
h. Remove A5A cross-trip action

Figure 1 shows the map of the area of the proposed East-West Tie expansion. The existing stations and transmission lines and the general route of the new lines (not their actual right-of-way) are shown on this map.

Schematic diagrams of the existing and proposed transmission lines and station facilities are shown in Figure 2-5.

Figure 6 shows the contingencies and actions of NW SPS 2 after the revisions listed above.

3. Customer Impact Assessment Scope

The purpose of this CIA is to assess the potential impacts of the proposed new transmission facilities on the existing connected load and generation customers in the affected area.

A review of the following potential impacts on existing customers is conducted in this CIA:

- Short-circuit current
- Voltage
- Power supply reliability

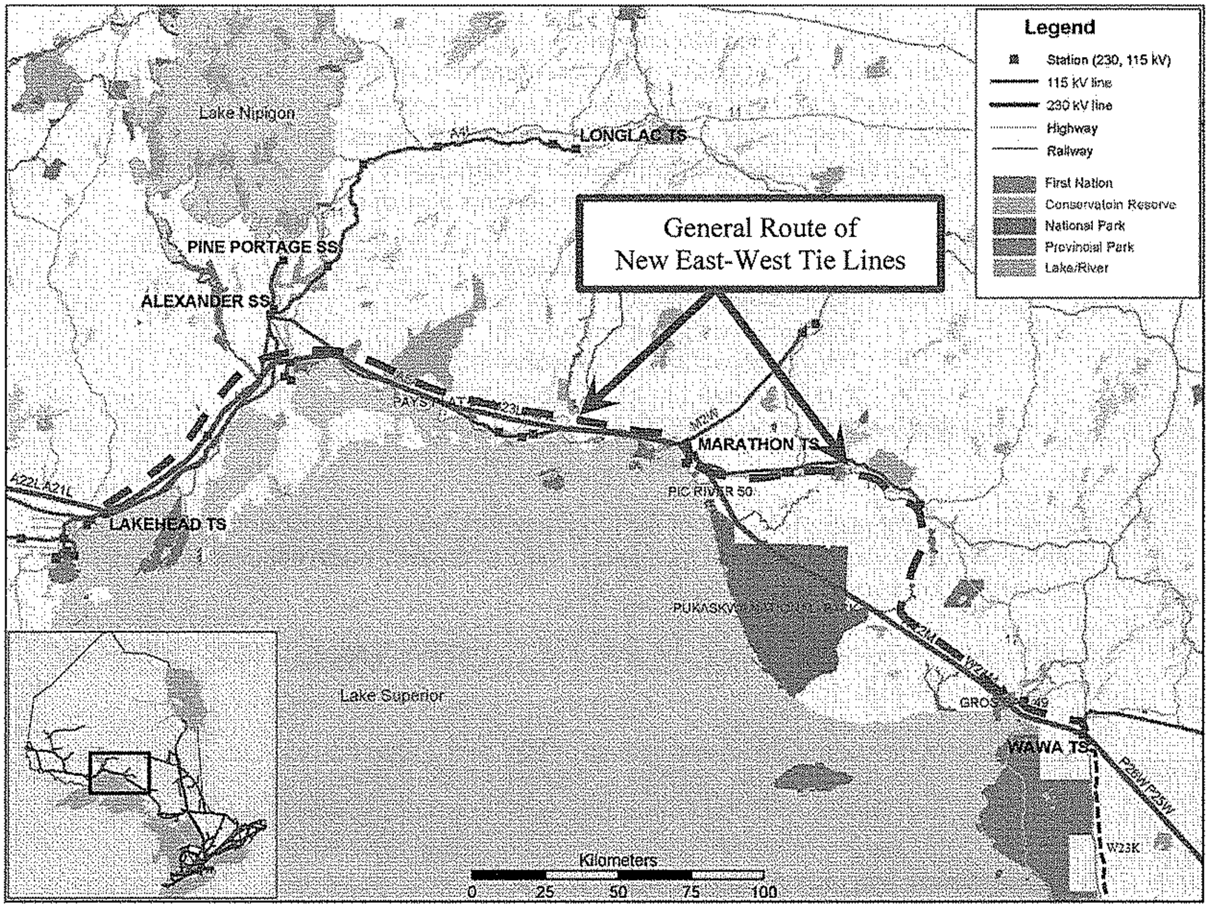

Figure 1: Area of East-West Tie Expansion

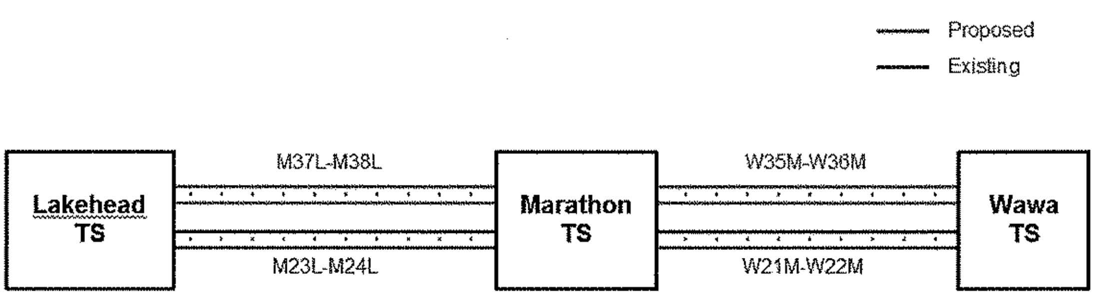

Figure 2: Schematic Diagram of the Proposed and Existing 230 kV Transmission Lines between Wawa TS and Lakehead TS

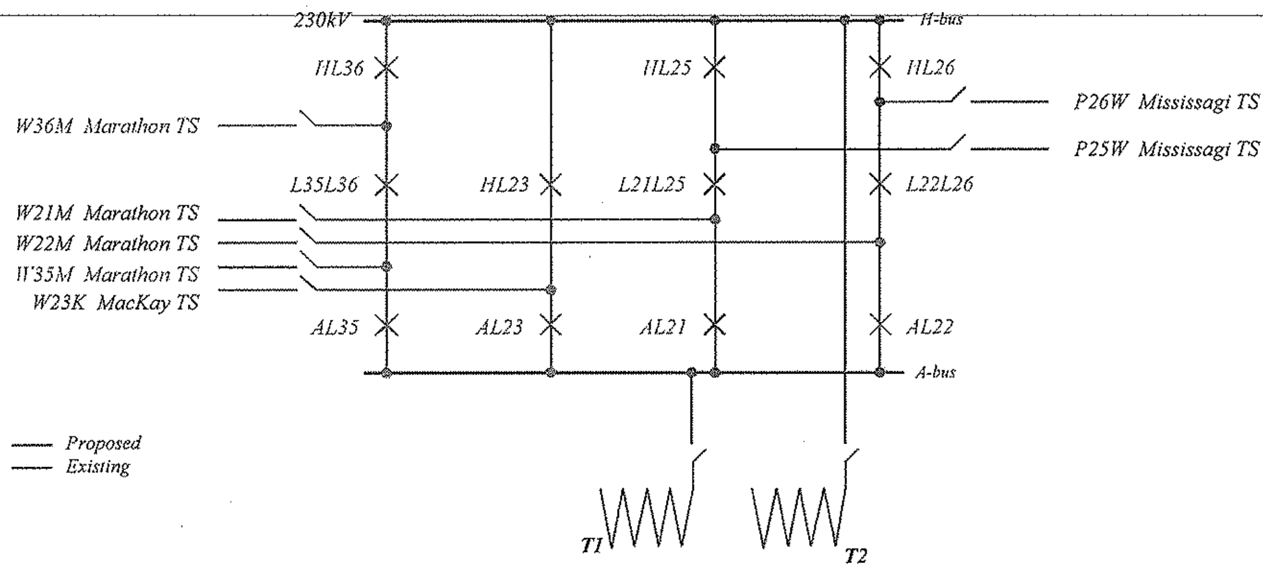

Figure 3: Schematic Diagram of Wawa TS (230 kV Facilities)

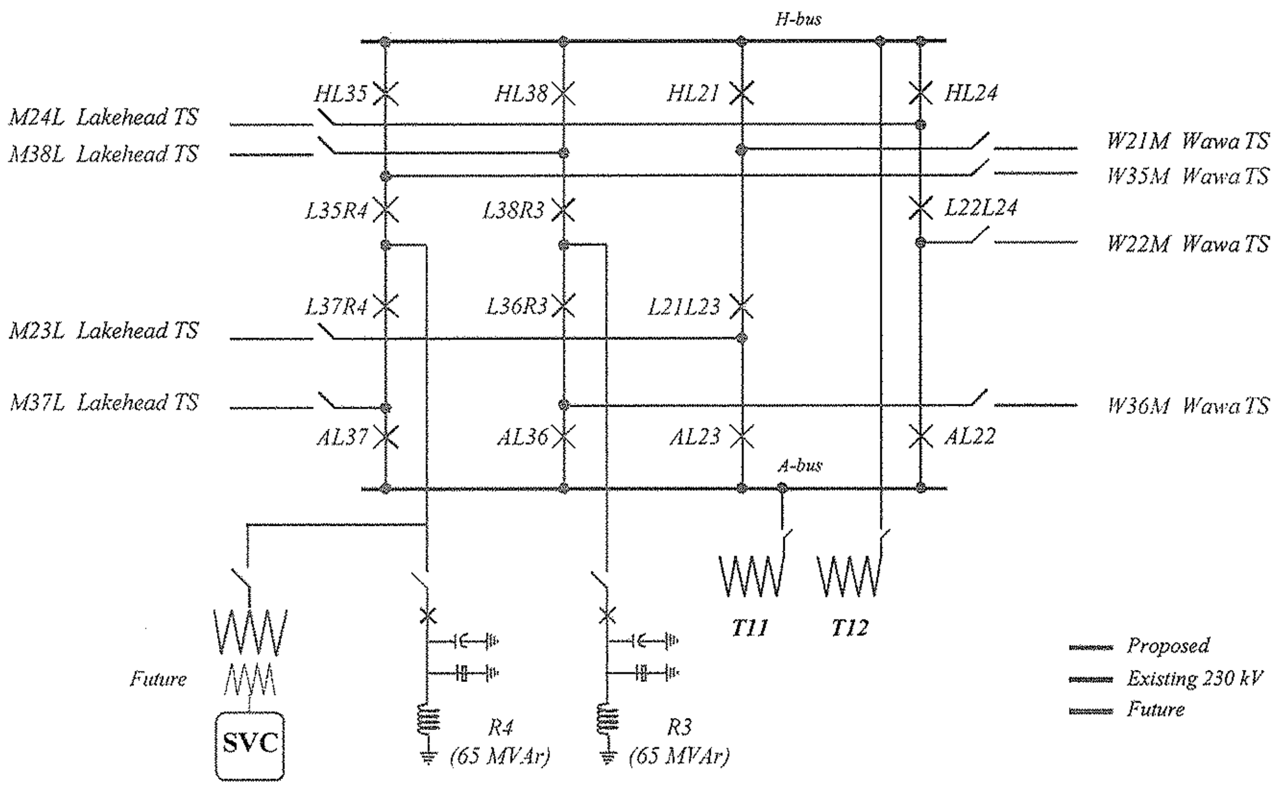

Figure 4: Schematic Diagram of Marathon TS (230 kV Facilities)

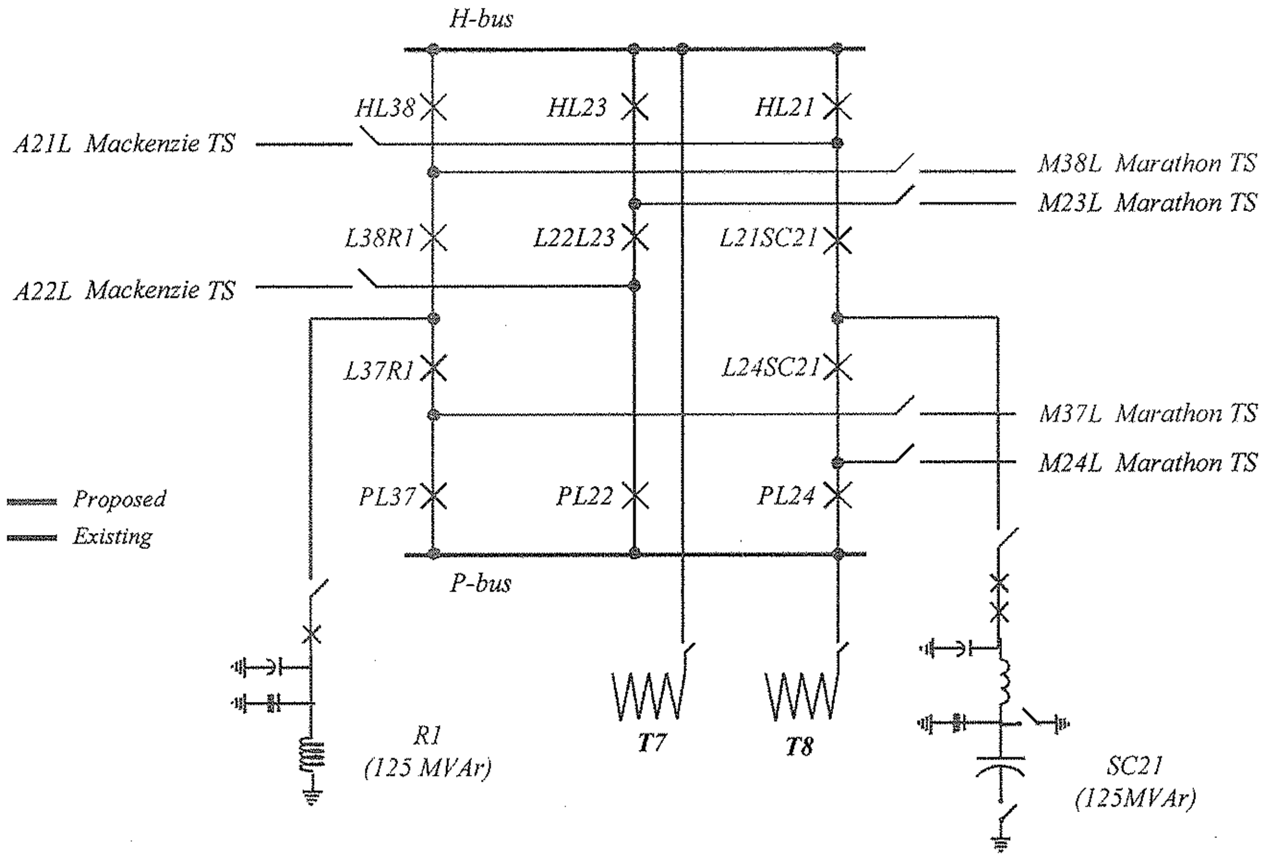

Figure 5: Schematic Diagram of Lakehead TS (230 kV Facilities)

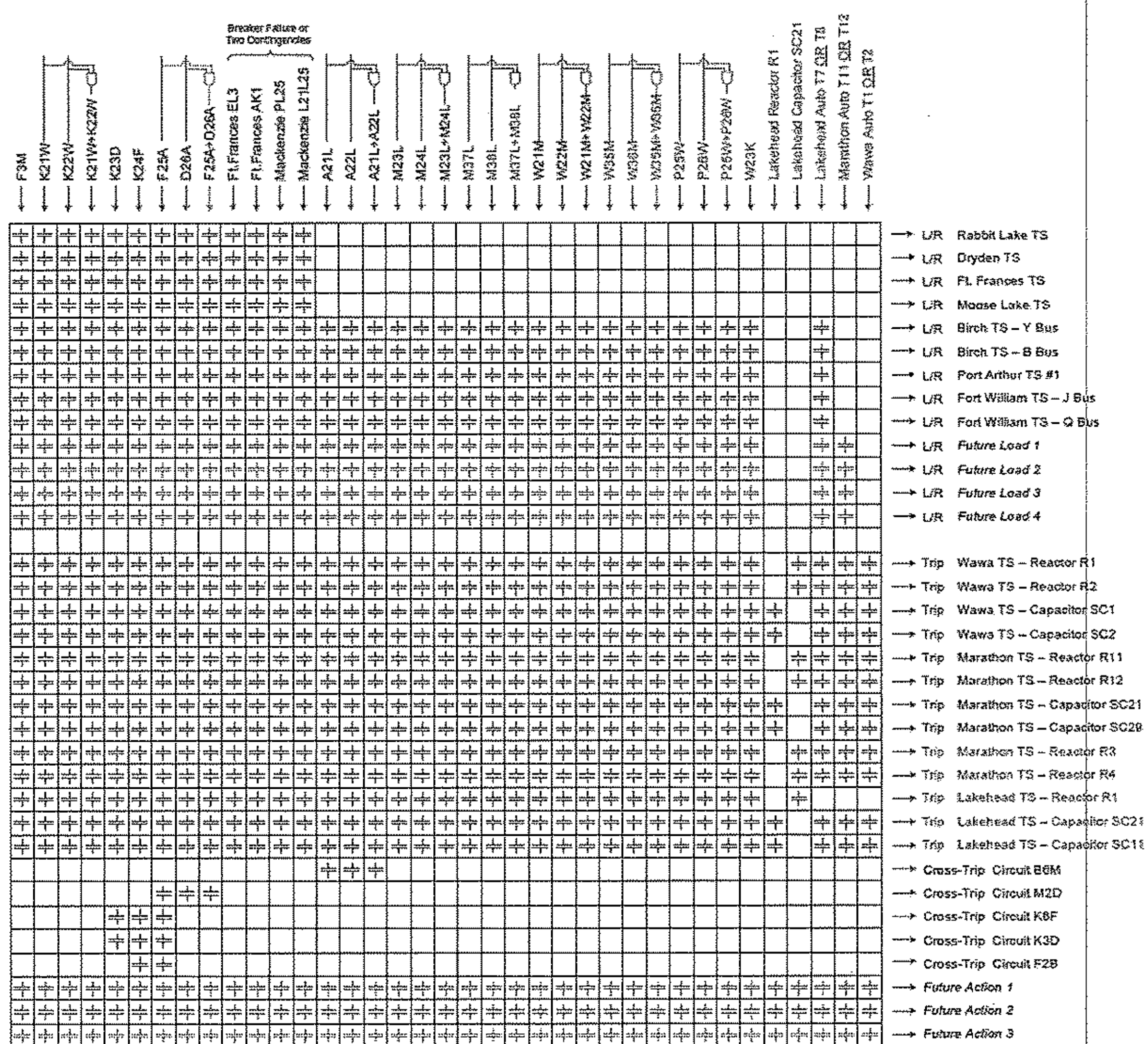

Figure 6: Revised Northwest SPS (NW SPS 2) Contingencies, Actions and Selection Matrix

4. Short-Circuit Impact

The proposed transmission reinforcement has a relatively small impact on Short-Circuit Levels in the area since, it does not significantly reduce the net (equivalent) impedance between the existing sources of short-circuit current, i.e. generators, and the customer connection points.

Table 2 shows the short-circuit currents (Symmetrical and Asymmetrical; for three-phase faults and single-phase-to-ground faults) at the main buses in the area, before and after the connection of the new East-West Tie, with the assumption of all existing and committed generators being in service, including Atikokan and one Thunder Bay unit. Table 3 shows the change in the short-circuit current as a result of the project.

As can be seen in Table 3, the increase in short-circuit currents at main buses are relatively small. The biggest increase, close to 2 kA, is at Marathon 230 kV bus, however as seen in Table 2, at this location at present the short-circuit current is relatively low (below 6 kA). At Lakehead 115 kV bus, where the short-circuit current approaches 22 kA at present, there will be an increase of less than 1.3 kA.

At Terrace Bay and Aguasabon the increase in short-circuit current is less than 100 A. The increase in short-circuit current at other locations in the area are similar or smaller than the change at the nearby buses shown in Table 3.

Table 2: Short-Circuit Currents at Main Buses

	Before E-W Tie Expansion				**After E-W Tie Expansion**			
	Three Phase SC Current (kA)		Line to Ground SC Current (kA)		Three Phase SC Current (kA)		Line to Ground SC Current (kA)	
Station / Bus	Symm	Asymm	Symm	Asymm	Symm	Asymm	Symm	Asymm
MacKenzie 230 kV	6.319	8.008	6.515	8.455	6.418	8.124	6.593	8.542
MacKenzie 115 kV	5.940	7.240	7.128	9.090	5.980	7.281	7.167	9.132
Lakehead 230 kV	7.324	9.126	7.523	9.861	8.184	10.156	8.353	10.886
Lakehead 115 kV	16.895	18.926	18.714	21.905	17.892	20.084	19.749	23.143
Marathon 230 kV	5.236	5.815	5.072	5.836	6.988	7.994	6.737	7.915
Marathon 115 kV	7.065	7.523	8.318	9.082	8.109	8.941	9.532	10.773
Wawa 230 kV	6.818	7.815	6.127	7.710	7.671	8.837	6.943	8.745
Wawa 115 kV	7.874	8.777	9.456	11.088	8.299	9.342	9.977	11.826
Terrace Bay 115 kV	4.723	5.703	3.702	4.341	4.810	5.793	3.740	4.378
Aguasabon 115 kV	4.561	5.284	3.955	4.929	4.633	5.356	3.992	4.969

Table 3: Increase in Short-Circuit Currents As a Result of East-West Tie Expansion

Station / Bus	Three Phase SC Current Increase (kA)		Line to Ground SC Current Increase (kA)	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
MacKenzie 230 kV	0.099	0.116	0.078	0.087
MacKenzie 115 kV	0.040	0.041	0.039	0.042
Lakehead 230 kV	0.860	1.030	0.830	1.025
Lakehead 115 kV	0.997	1.158	1.035	1.238
Marathon 230 kV	1.752	2.179	1.665	2.079
Marathon 115 kV	1.044	1.418	1.214	1.691
Wawa 230 kV	0.853	1.022	0.816	1.035
Wawa 115 kV	0.425	0.565	0.521	0.738
Terrace Bay 115 kV	0.087	0.090	0.038	0.037
Aguasabon 115 kV	0.072	0.072	0.037	0.040

5. Voltage Impact

Addition of the new facilities improves the voltage performance in the area as a result of the strengthened transmission system and the addition of new shunt reactors and capacitor bank. These reactive power devices will allow the existing SVC and the Synchronous Condenser (SC) at Lakehead TS to be utilized more effectively for maintaining acceptable voltages before and after contingencies and switching actions.

Switching Assessment

Table A.1 in the appendix shows the change of voltage at the main buses and customer connection points following the switching of the new capacitor bank at Lakehead TS and the new shunt reactor at Marathon TS.

The largest voltage change following Lakehead TS capacitor bank switching is 2.94% (at Lakehead 230 kV bus), which is below the 4% maximum voltage change criteria in the Ontario Resource and Transmission Assessment Criteria (ORTAC). Normally, the capacitor bank will be switched in (out) when the SVC and SC at Lakehead TS are producing (absorbing) reactive power, i.e., they have room to reduce (increase) their reactive power output in response to the capacitor bank switching and reduce the impact on voltages. Similarly the new Lakehead TS shunt reactor will be switched in (out) when the SVC and SC are absorbing (producing) reactive power and they will reduce the impact on voltages.

The largest voltage change following the new Marathon TS shunt switching is 2.36% (at Marathon 230 kV bus), which is also below the 4% maximum voltage change criteria in ORTAC.

Steady State Voltage Assessment

The pre-switching (base case) voltages shown in Table A.1, for a medium transfer scenario, are within the ORTAC criteria of,

220 kV < Voltage of 230 kV buses < 250 kV
113 kV < Voltage of 115 kV buses < 127 kV

The IESO's SIA (CAA ID 2016-568) has examined the voltage performance of the main buses for double-circuit contingencies as well as single and double outage/contingency of transformers and shunt reactors. It has found that pre-contingency and post-contingency voltage of the main buses remain within the ORTAC criteria for low, medium and high transfer scenarios.

NW SPS 2 will allow the voltages to be controlled within the ORTAC criteria following contingencies under various East-West transfer conditions, by switching the shunt capacitor banks and reactors in the area, or even rejecting some of the loads, if necessary, for severe contingencies or outage conditions.

6. Supply Reliability Impact

Currently simultaneous loss of the existing double-circuit lines, or loss of one circuit when the companion circuit is out of service, will result in the separation of Northwest Ontario from the rest of the system, limiting the pre-contingency East-West transfer.

The IESO's SIA (CAA ID 2016-568) has determined that the addition of the new double-circuit lines and the station facilities will allow up to 450 MW transfer between Northeast and Northwest Ontario, respecting possible double-circuit and breaker fault/failure contingencies (resulting in simultaneous loss of two transmission elements).

Addition of the new circuits, reconfiguration of Wawa TS and Marathon TS from ring bus to bus-diameter arrangement and compliance with the planning and operating requirements of the NERC and NPCC reliability standards will improve the security and reliability of supply for the affected customers.

Customer Impact during Construction

The outage schedule during the construction work will be developed during detailed engineering and execution phase of the project. Construction will be staged by Hydro One and the IESO to minimize possible customer interruptions. The outage and recall durations will be minimized and the risk will be managed with proper outage planning and co-ordination. The schedules will be communicated to the affected customers and stakeholders in advance of the outages.

7. Conclusions

This CIA report describes the impact of the proposed East-West Tie expansion, i.e. the new 230 kV transmission lines and station facilities and reconfigurations, on the customers in the area.

The short-circuit levels at customer transmission connection points will not increase significantly as a result of this project.

The voltage assessments described in the SIA (CAA ID 2016-568) report and the switching studies described in this CIA report show that voltage performance remains within the Planning Criteria. The new reactive power sources and the revised Northwest SPS (NW SPS 2) will improve the voltage performance in the area.

The proposed transmission facilities have no material adverse reliability impact on existing customers in the area, on the contrary, the reliability will improve in Northwest Ontario.

Appendix

Switching Assessment Results

Table A.1 shows the voltage of main buses and customer connection points before and after,

- Switching off the new 230 kV capacitor bank at Lakehead TS, and
- Switching on the new 230 kV shunt reactor at Marathon TS

It also show the change in voltages (delta-V) for the above

Table A.1: Voltages Before and After Switching of New Capacitor Bank and Reactor

Name & Nominal kV Of Bus or Connection Point	Pre-Switching Voltage (kV)	After Lakehead Capacitor Switching		After Marathon Reactor Switching	
		Voltage (kV)	delta-V%	Voltage (kV)	delta-V%
ATIKOKAN_TGS, 230	239.35	235.00	-1.8	240.75	0.6
AUBRY_FLSJ25, 230	242.39	241.47	-0.4	243.81	0.6
DRYDEN_TS , 230	238.21	235.77	-1.0	238.93	0.3
FT_FRANCES , 230	241.39	238.81	-1.1	242.13	0.3
GRNW_LK_JM23, 230	230.03	223.84	-2.7	232.99	1.3
LAKEHEAD_TS , 230	228.16	221.44	-2.9	230.47	1.0
MACKENZIE_TS, 230	239.71	235.37	-1.8	241.11	0.6
MARATHON_TS , 230	229.97	226.18	-1.6	235.39	2.4
MISSISSAGI , 230	241.76	241.07	-0.3	242.88	0.5
WAWA_TS , 230	236.10	234.06	-0.9	239.14	1.3
ABITIBI_JQ4B, 115	121.54	119.91	-1.3	122.13	0.5
ABITIBI_JQ5B, 115	120.34	118.58	-1.5	121.00	0.6
AGUASABON_SS, 115	123.49	122.55	-0.8	124.70	1.0
ALEXANDER_SS, 115	125.75	124.93	-0.6	126.08	0.3
ANIMKI_JCT, 115	119.01	117.48	-1.3	121.67	2.2
AP_NIPIGON , 115	125.01	124.11	-0.7	125.30	0.2
BEARDMORE_J , 115	124.10	123.13	-0.8	124.36	0.2
BIRCH_TS , 115	120.71	118.91	-1.5	121.37	0.5
BLACK_R_JM2W, 115	122.91	121.37	-1.3	125.49	2.1
BOWATER_G6 , 115	121.89	120.31	-1.3	122.46	0.5
FT_WILLM_Q4B, 115	120.68	118.97	-1.4	121.31	0.5
FT_WILLM_Q5B, 115	120.00	118.23	-1.5	120.66	0.6
HEMLO_MINE_J, 115	119.11	117.57	-1.3	121.76	2.2
INCO_SHEB_J , 115	120.82	119.08	-1.4	121.44	0.5
JELLICOE_#3J, 115	122.73	121.67	-0.9	122.93	0.2

Name & Nominal kV Of Bus or Connection Point	Pre-Switching Voltage (kV)	After Lakehead Capacitor Switching		After Marathon Reactor Switching	
		Voltage (kV)	delta-V%	Voltage (kV)	delta-V%
KASHABOWIE_J, 115	120.88	119.12	-1.5	121.49	0.5
LAC_DES_CSS , 115	120.71	119.63	-0.9	121.09	0.3
LAC_DES_ILSJ, 115	120.74	119.66	-0.9	121.12	0.3
LAKEHEAD_TS , 115	123.05	121.05	-1.6	123.75	0.6
LONGLAC_TS , 115	120.41	119.31	-0.9	120.61	0.2
MACKENZIE_A3, 115	119.93	118.02	-1.6	120.54	0.5
MANITOUWADGE, 115	126.09	124.18	-1.5	128.65	2.0
MARATHN_DS_J, 115	125.52	123.80	-1.4	128.08	2.0
MARATHON_TS , 115	125.75	123.99	-1.4	128.38	2.1
MINNOVA_J , 115	124.02	123.11	-0.7	125.08	0.9
MOOSE_LK_TS , 115	120.39	118.60	-1.5	120.97	0.5
MURILLO_J , 115	120.62	118.94	-1.4	121.24	0.5
NIPIGNON_J , 115	125.21	124.21	-0.8	125.57	0.3
PIC_J_M2W , 115	125.79	124.02	-1.4	128.42	2.1
PIC_J_T1M , 115	125.60	123.88	-1.4	128.16	2.0
PT_ARTH_#1A1, 115	122.10	120.18	-1.6	122.79	0.6
RED_ROCK_J , 115	125.13	124.13	-0.8	125.49	0.3
RESFP_KRFTQ4, 115	120.41	120.41	0.0	120.41	0.0
RESFP_KRFTQ5, 115	120.19	118.48	-1.4	120.86	0.6
RESFP_TB_Q5B, 115	120.23	118.48	-1.5	120.89	0.6
SAPAWE_J_B6M, 115	120.61	118.82	-1.5	121.20	0.5
SCHREIBER_J , 115	123.76	122.84	-0.7	124.89	0.9
SHABAQUA_JB6, 115	120.73	119.00	-1.4	121.35	0.5
SILVER_FALLS, 115	120.99	119.99	-0.8	121.34	0.3
STANLEY_JB6M, 115	120.65	118.97	-1.4	121.28	0.5
TCP_NIPIGN_J, 115	125.01	124.11	-0.7	125.30	0.2
TER_BAY_PU_J, 115	123.34	122.34	-0.8	124.67	1.1
TERRACE_BAY , 115	123.34	122.34	-0.8	124.67	1.1
THUN_BAY_Q9B, 115	120.69	118.89	-1.5	121.35	0.5
UMBATA_FLS_J, 115	121.83	120.35	-1.2	124.40	2.1
WAWA_TS , 115	125.36	124.54	-0.6	126.64	1.0
WILLIAMS_M_J, 115	119.20	117.67	-1.3	121.85	2.2
WILLROY_J , 115	126.09	124.19	-1.5	128.65	2.0
WHITE_RIVER, 115	117.81	116.26	-1.3	120.51	2.3