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November 8, 2018

DELIVERED VIA RESS AND COURIER

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON, M4P 1E4
Attn: Ms. Kirsten Walli
Board Secretary

Dear Ms. Walli:

Re: IAMGOLD'S Application for Leave to Construct Transmission Facilities in the District of Sudbury, Ontario
OEB File No. EB-2018-0191
Written Submissions - Mattagami First Nation

Pursuant to the Ontario Energy Board ("OEB") revised Procedural Order No. 1 dated October 9, 2018, Mattagami First Nation ("MFN") is filing its written submissions to the OEB.

Please contact the undersigned should you have any questions.

Yours truly,

Olthuis, Kleer, Townshend LLP

JACYNTHE LEDOUX for NANCY KLEER

cc. Chief Chad Boissoneau, Mattagami First Nation

ONTARIO ENERGY BOARD

EB-2018-0191

WRITTEN SUBMISSIONS

FROM

MATTAGAMI FIRST NATION ("MFN")

To:

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attn: Ms. Kirsten Walli
Board Secretary

Introduction

1. IAMGOLD is proposing to supply a new mining development ("Cote Gold") by (i) building approximately 44 kilometers of 115kV transmission line, (ii) providing connection facilities at Hydro One Networks Inc. ("HONI") Shining Tree Junction ("Shining Tree JCT"), and (iii) constructing facilities at the Mine (collectively (i), (ii) and (iii) the "Project").[1] To supply this new mining development, HONI is proposing to re-energize the idle 115 kV T2R transmission line supplied from Timmins TS in northern Ontario.

2. The Mattagami First Nation ("MFN") is among the "Indigenous communities most affected by the Project".[2] MFN is supplied electricity by the Shining Tree DS which is supplied by T61S, a 115kV transmission line running parallel to the T2R connecting to Timmins TS.

3. MFN has two primary considerations for the IAMGOLD Cote Gold Section 92 application:

   a) Will the Project increase the probability that MFN will experience lower reliability in the near-term; and

   b) Can the Project be optimized to increase reliability for MFN in the long-term.

4. MFN's considerations pertaining to reliability of electricity services to consumers are within the scope of the OEB's jurisdiction under s. 96(2) of the *Ontario Energy Board Act*[3], as confirmed by Procedural Order No. 1[4].

[1] EB-2018-0191, IAMGOLD Application, Exhibit B, Tab 1, Schedule 1, July 6, 2018, at p 2.
[2] As acknowledged by IAMGOLD in EB-2018-0191, IAMGOLD Application, Exhibit H, Tab 1, Schedule 1, July 6, 2018, at p 2 – line 25.
[3] SO 1998, c 15, Sch B [the "*Act*"].

Lower reliability for MFN is unlikely in the near-term

5. MFN, with support from their consultant Power Advisory LLC ("Power Advisory"), has reviewed the System Impact Assessment ("SIA") for Cote Gold.[5] The SIA assesses 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 conditional approvals or disapproval of the proposed connection.

6. MFN and Power Advisory have also reviewed the Customer Impact Assessment ("CIA") for Cote Gold.[6] The intent of the CIA is to highlight significant impacts, if any, to affected transmission customers and allow an opportunity for potential solutions to be proposed to resolve identified impacts.

7. The proposed connection arrangement for Cote Gold maintains the existing supply path for the MFN community other than two exceptions:

   a) The SIA requires HONI, the transmitter, to install a normally open interrupting switch between the two Timmins 115kV buses; and

   b) The CIA indicates the installation of a locally operated mid-space opener ("MSO") that is normally open between T61S and T2R at the Shining Tree JCT.[7]

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[4] EB-2018-0191, Procedural Order No 1, October 4, 2018, at p 1.
[5] CAA ID-2017-623, IESO, System Impact Assessment Report – Connection Assessment & Approval Process for the Cote Gold Project, June 6, 2018, online: http://www.ieso.ca/-/media/Files/IESO/caa/CAA_2017-623_Final_Report.pdf [See Appendix A].
[6] EB-2018-0191, IAMGOLD - Customer Impact Assessment, IAMGOLD Cote Lake Mine Connection, Filed September 27, 2018.
[7] EB-2018-0191, IAMGOLD - Customer Impact Assessment, IAMGOLD Cote Lake Mine Connection, Filed September 27, 2018, Figure 2, at p 7.

8. MFN's assessment is that neither of the changes is expected to result in lower reliability for Shining Tree DS in the near-term. The proposed changes are not expected to reduce the ability of the transmission network supplying the MFN community to maintain supply under different outage situation. In particular, it is not expected that the instances of loss of supply to the Shining Tree DS will increase due to the proposed changes identified in the SIA and CIA.

9. In actuality, the separation of the Timmins 115kV buses by the normally open interrupting switch should provide the opportunity for increased reliability by offering the ability for Timmins TS to supply T61S and T2R from effectively two different supply points (i.e., two different buses).

Opportunity to increase reliability for Shining Tree DS

10. In their IR response to MFN-3, IAMGOLD states:

> "*The primary reason for the installation of the MSO between the two circuits is to allow for Shining Tree distribution station to be fed from line T2R while line T61S is re-conductored during Hydro One's proposed upgrade of the transmission line between Timmins substation and Shining Tree distribution station.*
>
> […]
>
> *Under normal operating conditions, the T61S and T2R circuits are run independently from different busses within the Timmins substation. Neither circuit has or will have sufficient capacity to supply the existing T61S circuit loads and the anticipated Cote Gold load. The use of the MSO at Shining Tree Junction would require planning and coordination between all the customers fed from the*

two circuits and given the proximity to both Timmins and Sudbury, coordinating a crew to operate the MSO is not considered to be problematic." [8]

11. MFN is not convinced that there is limited capacity to share between the two transmission lines during emergency outage events. That is, MFN believes there is an opportunity for T2R and T61S to provide an alternative supply path for their primary load customers in the instances where one transmission line is out of service (i.e., a planned or unplanned outage).

12. IAMGOLD has stated in MFN-1 that the peak monthly demand for Cote Gold is estimated to be 72 MW and is expected to be consistent 24 hours/day for 365 days/year.[9] In the IAMGOLD SIA, the IESO shows that T61S supplies three distribution stations (DS): Shining Tree DS, Weston Lake DS, and Timmins West Mine Customer Transformer Station (CTS). The SIA goes on to estimate the long-term peak demand forecast for each DS until 2031.[10]

13. The table below shows the summer peak demand forecast for each DS and Cote Gold for 2022 (when Cote Gold is expected to be at full operation) and for 2031. The IESO conclusion is that there will be no load growth over the next decade for load supplied by T61S and therefore that the total load supplied for T61S and T2R will be <100 MW over the long-term.

[8] EB-2018-0191, IAMGOLD Response to MFN IRs, filed on October 17, 2018, MFN-3(c) at p 3.
[9] EB-2018-0191, IAMGOLD Response to MFN IRs, filed on October 17, 2018, MFN-1(a) at p 1.
[10] See Appendix A.

Table 1: Summer Peak Load Forecast for local DS and IAMGOLD project[11]

Summer Peak Load Forecast (MW)	**2022**	**2031**
Shining Tree DS	3.3	3.3
Weston Lake DS	4	4
Timmins West Mining CTS	13	13
Cote Gold (IAMGOLD)	72	72
TOTAL Peak Load Forecast	**92.3**	**92.3**

14. The SIA provides an estimate of the rating for transmission lines under continuous, Long-Term Emergency (LTE), and Short-Term Emergency (STE) operation.[12] The rating and an estimated calculation of MVA for T2R is provided in the table below. The SIA did not provide a rating for T61S. MFN has assumed that the rating for T61S is the same or greater than the rating listed for T2R. The results shown in the table below suggest that there is available capacity under continuous, LTE, and STE operations to supply the all of the above-mentioned loads on either T2R or T61S.

Table 2: Line rating for T2R under different operating conditions[13]

	Rating (Amps)		**Rating (MVA)**	
T2R (Timmins to Shining Tree JCT)	**Summer**	**Winter**	**Summer**	**Winter**
Continuous	670	780	133	155
LTE	850	850	169	169
STE	920	920	183	183

MVA rating calculation assuming 115kV Line-to-Line voltage and a 1.0 Power Factor (PF)

[11] See Appendix A, Table 7, at p 20 and EB-2018-0191, IAMGOLD Response to MFN IRs, filed on October 17, 2018, MFN-1(a) at p 1.
[12] Continuous: Rating calculated at the lesser conductor temperature of 93°C or sag temperature.
LTE: Rating calculated at lesser conductor temperature of 127°C or sag temperature.
STE: Rating calculated at the sag temperature with a pre-contingency loading of 100% of the continuous rating. See Appendix A at p 25.
[13] See Appendix A,Table 11 at p 25.

15. In addition, the IESO calculated post-contingency load flows in the IAMGOLD SIA for T2R and concludes that loading on T2R would be ~40%.[14] The post-contingency analysis completed by the IESO further suggests that there is ample capacity on the T2R for additional load during contingency events.

16. Therefore, MFN concludes there is an opportunity for the re-energization of T2R to provide an alternative supply path for T61S and Shining Tree DS during contingency events that will reduce the duration of outages experienced by the MFN community due to loss of supply (i.e., loss of supply from the transmission network).

Options to increase reliability for MFN community

17. MFN believes there is an opportunity to increase the reliability of supply for Shining Tree DS in a cost-effective manner.

18. As demonstrated, MFN believes there is available capacity on the T2R or T61S to provide an alternative supply path should an outage occur on either transmission line. The installation of a normally open interrupting switch on the Timmins 115kV bus separates the supply for each transmission line therefore ensuring an outage on either bus does not interrupt supply on the other bus.

19. MFN recommends that IAMGOLD review the following option to increase reliability for Shining Tree DS supply:

    a) Installation of MSO on T61S and MSO on T2R at Shining Tree JCT to allow isolation of either transmission line segments from Timmins TS in case of an

[14] See Appendix A, Table 12 at p 26.

outage at the bus or on the line (e.g., outage due to falling tree on line). These MSOs can be operated to provide an alternative supply path during the planned or unplanned outage for all load on T61S and T2R through Shining Tree JCT.

20. The Shining Tree DS is approximately 100 km from Timmins, which is likely the closest service center for HONI reliability crews to be dispatched from to repair the transmission network during an outage event. The installation of additional MSOs will allow the reliability crew to isolate the outage as a first step allowing electricity supply to be returned before the outage event has been cleared.

MFN's Proposed Conditions of Approval

21. The *Act* permits the OEB, when making an order, to "impose such conditions as it considers proper".[15] In addition to standard conditions of approval[16], MFN proposes that a project-specific condition of approval be placed on IAMGOLD in the event that they are granted leave to construct the new transmission line.

22. MFN proposes the following additional project-specific condition of approval to be placed on IAMGOLD, should the IAMGOLD Application be granted leave to construct by the OEB:

    a) IAMGOLD shall ensure the installation of an additional MSO on T61S and an additional MSO on T2R at Shining Tree JCT, or other cost-effective solutions, to increase the reliability for Shining Tree DS.

[15] *Ontario Energy Board Act, 1998*, s. 23(1).
[16] EB-2016-035, Hydro One's West Toronto Transmission Enhancement Project, Decision and Order, April 27, 2017, Appendix B – Conditions of Approval.

Application for Costs

23. As mentioned in their intervention request, MFN will be requesting an award of costs for their participation in this proceeding pursuant to section 3.03(b) and (c) of the Board's Practice Direction. MFN is requesting the OEB to advise, as soon as possible, on the timing and the procedure for this Application for Costs.

All of which is respectfully submitted.

IAMGOLD Corporation

Application for Leave to Construct Transmission Facilities in the District of Sudbury, Ontario

EB-2018-0191

MFN WRITTEN SUBMISSIONS

Appendix A

November 8, 2018

REPORT

System Impact Assessment Report

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID: **2017-623**

Project: **Cote Gold Project**

Connection Applicant: **Iamgold Corporation**

Engineering Studies Department

Independent Electricity System Operator

June 6, 2018

Public

Document Name	System Impact Assessment Report
Issue	1.0
Reason for Issue	First issue
Effective Date	June 6, 2018

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, including but not limited to changes to the information available to or system assumptions made by the IESO at the time of the assessment.

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 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 and absolute discretion without notice to the connection applicant. Although the IESO will make reasonable 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 connection 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 project 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 project 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

Conditional Approval for Connection

Iamgold Corporation (the "connection applicant") is proposing to construct a 44km 115 kV overhead line to supply a new mining facility, Cote Gold (the "project") in the community of Gogma, located in Northeastern Ontario, 114 km south of Timmins. The project will require connection to Shiningtree junction, located at the end of the presently idle 115 kV circuit T2R. T2R is fed from Timmins TS and is owned and operated by Hydro One Networks Inc. (the "Transmitter"). Figure 1 shows the transmission system in the vicinity of the Cote Gold Project.

From the Shiningtree Jct, the project's 44 km 115 kV overhead line will be connected to the project's 115 kV bus via a motorized disconnect switch and a circuit breaker. There are two 115/13.8 kV, 45/60/75 MVA step-down transformers with a motorized disconnect switch and a circuit breaker at the high-voltage side of each transformer. The low-voltage side of each transformer will be connected to separate 13.8 kV buses. The connection applicant is also proposing to install two +25/-5 Mvar SVCs connected to the 13.8 kV buses at the project. The proposed SVCs will be operated in voltage control mode to maintain the voltages at the 13.8 kV buses close to nominal voltage. Figure 2 shows the connection arrangement of the project.

The project will include four standby generators to provide power for essential loads in the event of total loss of power or connection with the transmitter. Therefore, they are not intended to operate in parallel with the grid and not included in the SIA study. It also includes two 7 MVA synchronous condensers, one on each bus, to increase short circuit level to meet the equipment operation requirement at the project. The two 7 MVA synchronous condensers will also help provide reactive power compensation. The synchronous condensers will be operated in reactive power control mode.

The proposed in-service date for this project is January 2021 with an eventual peak load of 72 MW split between the 13.8 kV buses.

This assessment concludes that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in this report are implemented. Therefore, the assessment supports the release of the Notification of Conditional Approval for Connection of the project.

Findings

The project's impact on the reliability of the integrated power system was evaluated, and based on the study results, the following was identified:

1. The project's connection arrangement and connection equipment are acceptable to the IESO.
2. The power transfer capability on the Hunta Flow South interface decreases 1.3% with the proposed project in-service. This meets the Ontario Resource and Transmission Assessment Criteria (ORTAC) requirement of less than 5%. See section 6.5 for further details.

3. The two proposed +25/-5 Mvar SVCs are adequate to maintain pre-contingency voltage above the minimum required by the ORTAC.
4. In assessing the project's equipment capability provided by the connection applicant the study results show that under an outage of one main step-down transformer the maximum flow on the companion transformer is 77.6 MVA. The connection applicant has confirmed that the main step-down transformers have a 10-day thermal rating higher than 78 MVA.
5. During summer peak load with heavy flow south of Porcupine TS, an outage of Hunta breaker L4L6 followed by an L5L6 Inadvertent Breaker Opening (IBO) results in the H6T line end opening at Hunta SS, causing the loading on circuit H7T to go above its STE rating. Similarly, H6T is overloaded during an outage of L4L7 followed by an L3L7 IBO. This is an existing issue and the proposed project makes the overloading conditions worse. Currently the issue can be managed by curtailing the generation in Northeast. However, it is recommended this be addressed by the transmitter. See section 6.5.2 for further details.
6. In all system conditions, during an outage of P13T, circuits T2R and H6T are connected radially to Hunta SS and the proposed load at the project cannot be supplied due to voltage collapse. This is addressed in requirement #2 for the transmitter. See section 6.4.2 for further details.
7. During an outage of Porcupine breaker K2K3, a K3K4 IBO contingency at Porcupine TS results in circuits P13T and T2R connected radially to Timmins TS and voltage collapse at the proposed project. Additionally, for an outage of Porcupine T3, a contingency involving T4 results in voltage collapse at the proposed project. These situations are addressed in requirement #3 for the transmitter. See section 6.6.1 for further details.
8. The loss of one SVC at the project results in the post-contingency voltage at the project's 115 kV bus below the 108 kV minimum required by the ORTAC. The connection applicant is proposing to implement a load rejection scheme that rejects the project's load upon the loss of the SVC(s).
9. Assuming the voltage at the Timmins 115 kV bus is at its maximum continuous voltage (138 kV), opening 115 kV circuit T2R results in a line end open voltage of 141.2 kV. This is addressed in requirement #3 for the connection applicant. See section 6.7 for further details.

IESO Requirements for Connection

Transmitter Requirements

The following requirements are applicable for the transmitter for the incorporation of the project:

(1) The transmitter is required to add new redundant protections for 115 kV circuit T2R at Timmins TS and modify the line protections of 115 kV circuits P13T and P15T, as identified in the Protection Impact Assessment (PIA).

The transmitter must submit any protection modifications that are different from those considered in this SIA at least six (6) months before any modifications are to be implemented on the existing protection systems. If those modifications result in adverse reliability impacts, mitigation solutions must be developed.

(2) The transmitter is required to install a normally open load interrupting switch between the two Timmins 115 kV buses. The switch must be operated closed during an outage of P13T to avoid voltage collapse at the project. The proposed tie switch is shown in Figure 4.

(3) The transmitter is required to include the proposed project in a Special Protection Scheme (SPS). The SPS must have the capability to trip the proposed project for the loss of 500 kV circuits D501P, P502X, Porcupine autotransformer T3 or T4, and opening of both K2K3 and K3K4 breakers (N-1-1) at Porcupine TS.

There are two options to implement the SPS for the proposed project: (a) expanding the existing Northeast Load and Generation Rejection (NE LGR) scheme to include the proposed project, provided the expanded SPS remains classified as Type III; or (b) creating a new Cote Gold SPS. The transmitter's decision will be subject to IESO approval.

(4) It is required that the transmitter install a disconnect switch at Shiningtree Jct on 115 kV circuit T2R to serve as the demarcation point between the equipment owned by the transmitter and the applicant. The transmitter must ensure that the disconnect switch meets all applicable requirements from the ORTAC and the TSC. The transmitter is required to register the disconnection switch during the IESO Market Registration process.

Connection Applicant Requirements

Project Specific Requirements:

The following specific requirements are applicable for the incorporation of the project. Specific requirements pertain to the level of reactive power compensation needed, operating restrictions, special protection system(s), upgrading of equipment and any project specific items not covered in the general requirements.

(1) The connection applicant is required to provide a detailed description of the proposed load shedding scheme to mitigate voltage issues following the loss of the SVCs at the project during the Market Registration process.

(2) It is required that a 6 Mvar reactor rated at 138 kV be installed at the project's 115 kV bus to control the voltage when line T2R is open at the proposed project. The reactor must be in-service for energizing the T2R line and out-of-service when the load at the proposed project is in service.

(3) The connection applicant did not provide a Short Term Emergency (STE) rating for the new T2R line section from Shiningtree Jct to the project. It is required that the connection applicant provide the rating during the Market Registration Process.

(4) The project shall participate in the SPS as described in requirement #3 for the transmitter. The connection applicant shall work together with the transmitter to implement the SPS.

General Requirements: The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code (TSC) and reliability standards. Some of the general requirements that are applicable to this project are presented in detail in Section 2 of this report.

IESO Recommendations for Transmitter

(1) It is recommended that the transmitter include the opening of Hunta SS 115 kV breakers L4L6+L5L6 and L3L7+L4L7 as recognized configurations that trigger selections for H6T and H7T contingencies, respectively, within the NE LGR scheme. This addresses finding #5.

(2) It is recommended that all the functionalities related to Timmins area load present in the NE LGR scheme be transferred to the new SPS if option (b) is chosen as described in transmitter requirement #3. Should the transmitter accept this recommendation, the transmitter will need to ensure that operation of all transferred functionalities do not take longer in the new scheme as compared to the NE LGR scheme.

– End of Section –

1. Project Description

Iamgold Corporation (the "connection applicant") is proposing to construct a 44 km 115 kV overhead line to supply a new mining facility, Cote Gold (the "project") in the community of Gogma, located in Northeastern Ontario, 114 km south of Timmins. The project will require connection to Shiningtree junction, located at the end of the presently idle 115 kV circuit T2R. T2R is fed from Timmins TS and is owned and operated by Hydro One Networks Inc. (the "Transmitter"). Figure 1 shows the transmission system in the vicinity of the Cote Gold Project.

From the Shiningtree Jct, the project's 44 km 115 kV overhead line will be connected to the project's 115 kV bus via a motorized disconnect switch and a circuit breaker. There are two 115/13.8 kV, 45/60/75 MVA step-down transformers with a motorized disconnect switch and a circuit breaker at the high-voltage side of each transformer. The low-voltage side of each transformer will be connected to separate 13.8 kV buses. The connection applicant is also proposing to install two +25/-5 Mvar SVCs connected to the 13.8 kV buses at the project. The proposed SVCs will be operated in voltage control mode to maintain the voltage at the 13.8 kV buses close to nominal voltage. Figure 2 shows the connection arrangement of the project.

The project will include four standby generators to provide power for essential loads in the event of total loss of power or connection with the transmitter. Therefore, they are not intended to operate in parallel with the grid and not included in the SIA study. It also includes two 7 MVA synchronous condensers, one on each bus, to increase short circuit level to meet the equipment operation requirement at the project. The two 7 MVA synchronous condensers will also help provide reactive power compensation. The synchronous condensers will be operated in reactive power control mode.

The proposed in-service date for this project is January 2021 with an eventual peak load of 72 MW split between the 13.8kV buses.

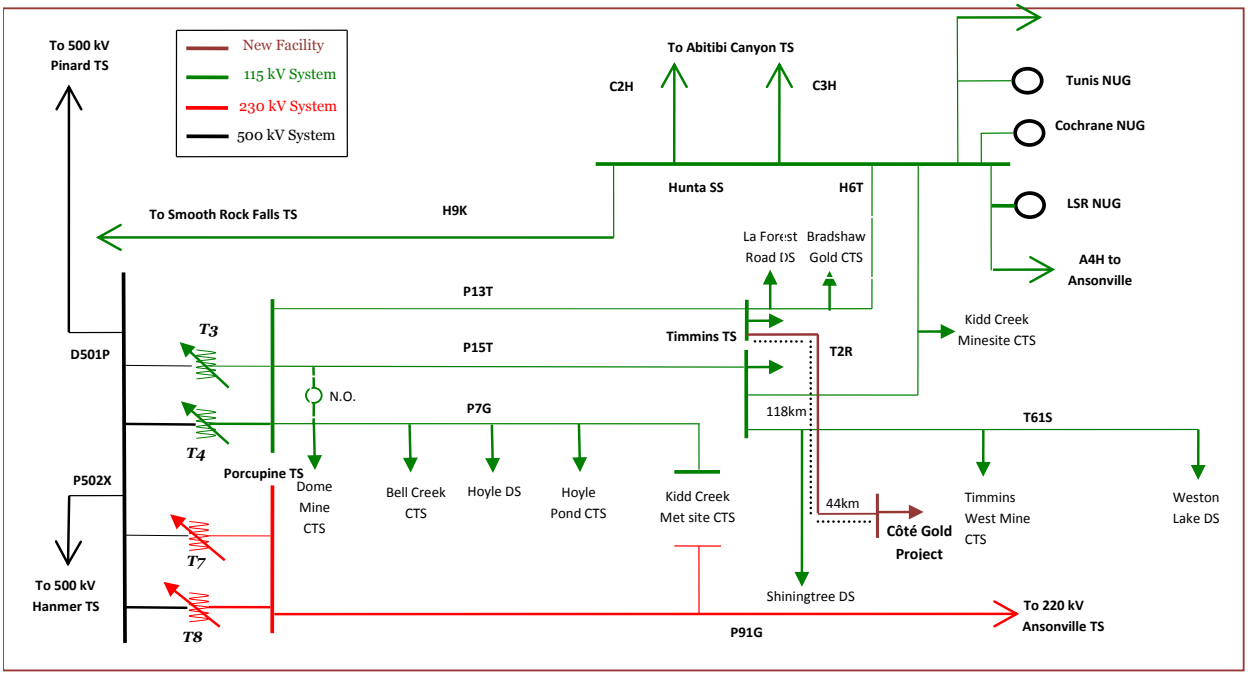

Figure 1: Transmission System in the vicinity of Cote Gold Project

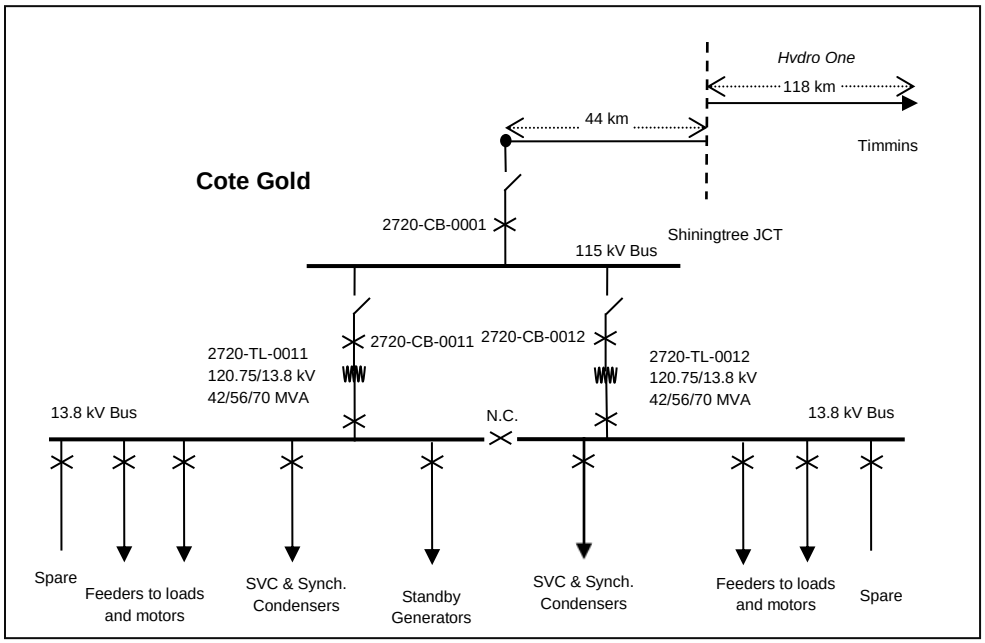

Figure 2: Connection Arrangement of Cote Gold Project

– End of Section –

2. General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules and the Transmission System Code. This section highlights some of the general requirements that are applicable to the project.

2.1 Reliability Standards

As currently assessed, the project does not fall within the North American Electric Reliability Corporation's (NERC) definition of the Bulk Electric System (BES) or the Northeast Power Coordinating Council's (NPCC) of the Bulk Power System (BPS). As such, the project does not have to meet NERC or NPCC requirements and is only required to meet obligations and requirements under the IESO's Market Rules at this time. However, like any other system element in Ontario, the BPS and BES classifications of this project will be periodically re-evaluated as the electrical system evolves.

2.2 Power Factor

As per Appendix 4.3 of the Market Rules, the connection applicant must have the capability to maintain the power factor within the range of 0.9 lagging and 0.9 leading as measured at the defined meter point of the project.

The defined meter point is typically defined as the high voltage side of the transformer. However, in the proposed project the defined meter point is at Shiningtree junction since the connection applicant owns the circuit from Shiningtree junction to Cote Gold.

The connection applicant has indicated that they will regulate power factor to 0.98 at the high voltage side of the transformer. Once the project is incorporated, if the IESO determines that the power factor is not within the required range, the connection applicant will be required to install reactive power compensation device(s) at the project.

2.3 Connection Equipment Design

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

2.4 Voltage

The connection applicant must ensure that the project's equipment meets the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC). The connection applicant must ensure that the project's 115 kV equipment can withstand the maximum continuous operating voltage in the Timmins area, 138 kV.

2.5 Fault Levels

As per the TSC, the connection applicant shall ensure the project's 115 kV connection equipment is designed to withstand the fault levels in the area. If any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to replace that

equipment with higher rated equipment capable of withstanding the increased fault level, up to maximum fault level specified in the TSC. Appendix 2 of the TSC establishes the maximum fault levels for the transmission system. For the 115 kV system, the maximum 3 phase and single line to ground symmetrical fault levels are 50 kA.

The connection applicant shall ensure that the 115 kV breakers installed at the project have a rated interrupting time of 5 cycles or less. Fault interrupting devices installed at the project must be able to interrupt fault currents at the maximum continuous voltage in the Timmins area, 138 kV.

2.6 Under Frequency Load Shedding

The connection applicant has an aggregate peak load at all its owned facilities, including the project, which is greater than 25 MW. Thus, the connection applicant is required to participate in the Under-Frequency Load Shedding (UFLS) program according to Section 11.3 of the Market Manual Part 7.1.

The connection applicant is required to install UFLS facilities at the project to allow for the detection of under-frequency conditions and the selection and tripping of load via circuit breakers.

The connection applicant must select 35% of aggregate peak load among its owned facilities for under-frequency tripping, based on a date and time specified by the IESO that approximates system peak, according to section 10.4 of Chapter 5 of the Market Rules.

As the connection applicant has a peak load of 50 MW or more and less than 100 MW at all its owned facilities, the UFLS relay connected loads shall be set to achieve the amount to be shed stated in the following table:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of Connection Applicant's Load	Cumulative Load Shed at stage as % of Connection Applicant's Load
1	59.5	0.3	≥ 17	≥ 17
2	59.1	0.3	≥ 18	≥ 35

Capacitor banks connected to the same facility bus as the load should be shed by UFLS relay at 59.5 Hz with a time delay of 3 seconds and should be coordinated in conjunction with the relevant transmitter, if applicable.

The maximum load that can be connected to any single UFLS relay is 150 MW to ensure that the inadvertent operation of a single under-frequency relay during the transient period following a system disturbance does not lead to further system instability.

2.7 Telemetry

In accordance with Section 7.5 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.17 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set forth in Appendix 4.22, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO Market Registration process.

The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market Rules. As part of the IESO Market Registration process, the connection applicant must also 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 Revenue Metering

If revenue metering equipment is being installed as part of the project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

2.9 Protection Systems

The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the Transmission System Code and any additional requirements identified by the transmitter. New protection systems must be coordinated with the existing protection systems.

The protection systems within the project must only trip the appropriate equipment required to isolate the fault. After the project begins commercial operation, if an improper trip occurs due to events within the project, the project may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

In the future, as the electrical system evolves, the project may have BES elements, or be placed on the BPS list, or designated as essential by either the IESO or by the transmitter. BPS and essential equipment must be protected by redundant protection systems in accordance with section 8.2.1a of the TSC. These redundant protections systems must satisfy all requirements of the TSC, and in particular, they must be physically separated, and not use common components. Protections for the transmission voltage BES elements must at least have redundant protective relays and redundant tripping circuitry, including dual breaker trip coils.

2.10 Restoration

According to the Market Manual 7.8 which states restoration participant criteria and obligations, the connection applicant is not required to be a restoration participant at this time.

As currently assessed by the IESO, the project is not classified as a Key Facility that is required to establish a Basic Minimum Power System following a system blackout. Key Facility and Basic Minimum Power System are terms defined in the NPCC Glossary of Terms.

2.11 IESO Market Registration Process

The connection applicant must initiate the IESO's Market Registration process at least eight months prior to the commencement of any project related outages.

The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration process to allow the IESO to incorporate this project into IESO work systems and to perform any additional reliability studies.

If the submitted equipment 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 the project and its connection facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm submitted 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.

Once the IESO's Market Registration process has been successfully completed, the IESO will provide the connection applicant with a Registration Approval Notification (RAN) document, confirming that the project is fully authorized to connect to the IESO-controlled grid. For more details about this process, the connection applicant is encouraged to contact IESO's Market Registration at market.registration@ieso.ca

During the IESO Market Registration process, a new Facility Description Document (FDD) for the proposed SPS must be provided six months prior to in-service. The FDD must contain the finalized SPS matrix as well as expected operating times. The actual operating times must be measured during commissioning, documented as a Performance Validation Record, and posted on Hydro One - IESO secured web portal.

If the FDD or performance testing as per the Performance Validation Record indicates a change in design or slower than expected operating times, than what was assumed in this assessment, then further analysis of the project will need to be done by the IESO. This may delay the grant of IESO final approval.

2.12 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/-/media/files/ieso/document-library/market-rules-and-manuals-library/market-manuals/market-administration/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 as "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. A project will be deemed by the IESO to be a committed project if:

(1) the connection applicant provides notification to the IESO specifying a defined and future-dated in-service date for the project, and;

(2) the connection applicant provides notification to the IESO indicating that project is actively being completed (i.e. not declared to be "on hold"), and;

(3) the connection applicant does one of the following:

- provides a notification to the IESO indicating that the connection applicant will be compensated with respect to the project through a power purchase contract, or rates set by the Ontario Energy Board,
- provides a notification to the IESO indicating that a leave to construct approval has been granted by the Ontario Energy Board,
- provides a notification to the IESO indicating that the project has a connection cost recovery agreement (CCRA) in place with the transmitter,
- provides a joint notification with the transmitter to the IESO indicating the project will come into service,
- provides notification through the IESO Facility Registration process that the project has started construction.

-End of Section-

3. Data Verification

3.1 Connection Arrangement

The connection arrangement of the project is shown in Figure 2. This arrangement is not expected to reduce the level of reliability of the integrated power system and is, therefore, acceptable to the IESO.

3.2 Connection Equipment

Table 1: 115 kV Transmission Line Data

	From Timmins to Shiningtree Jct	From Shiningtree Jct to Cote
Length	117.8 km	44 km
R	0.13075 pu	0.033344 pu
X	0.40973 pu	0.151562 pu
B	0.057143 pu	0.021826 pu
Continuous Rating (Summer/Winter)	670/780 A	1040/1200 A
LTE (Summer/Winter)	850/850 A	1266/1387 A
STE (Summer/Winter)	920/920 A	1266/1387 A*

*: The connection applicant did not provide STE ratings so it is assumed that the STE ratings will be the same as those for the LTE ratings in this study. The connection applicant will need to provide this rating during the IESO Market Registration Process.

Table 2: Main Step-Down Transformer Data

	2720-TL-0011	2720-TL-0012
Configuration	Three phase	Three phase
Transformation (kV)	120.75/13.8	120.75/13.8
Winding Configuration	Delta/Wye	Delta/Wye
Thermal Rating (MVA)	45 ONAN	45 ONAN
	60 ONAF	60 ONAF
	75 ONAF	75 ONAF
Impedance to Ground	HV: Ungrounded	HV: Ungrounded

	XV: grounded through resistance, limited to 50A for 10sec	XV: grounded through resistance, limited to 50A for 10sec
Positive Sequence Impedance	J0.075 on a 45 MVA base	J0.075 on a 45 MVA base
Under-load tap-changer	109.25 – 132.25 kV in 9 steps	109.25 – 132.25 kV in 9 steps
Off-load tap-changer	None	None

In assessing the project's equipment capability provided by the connection applicant the study results show that under an outage of one main step-down transformer the maximum flow on the companion transformer is 77.6 MVA. The connection applicant has confirmed that the main step-down transformers have a 10-day thermal rating higher than 78 MVA.

Table 3: 115 kV Circuit Breaker Specifications

Identifier	Voltage Rating	Interrupting time	Continuous Current Rating	Short Circuit Symmetrical Capability
2720-CB-0001	145 kV	50 ms	3150 A	40 kA
2720-CB-0011	145 kV	50 ms	3150 A	40 kA
2720-CB-0012	145 kV	50 ms	3150 A	40 kA

The 115 kV circuit breakers meet the maximum continuous voltage rating requirement of 138 kV. The interrupting time of the breakers meet the requirements of the TSC and the short circuit symmetrical interrupting capability of the breakers is higher than the fault levels in the area as shown in Section 4.

Table 4: 115 kV Disconnect Switch Specifications

Identifier	Voltage Rating	Continuous Current Rating	Short Circuit Symmetrical Rating
2720-DSW-0001	145 kV	1200 A	40 kA
2720-DSW-0011	145 kV	1200 A	40 kA
2720-DSW-0012	145 kV	1200 A	40 kA

The switches meet the required maximum continuous voltage and the short circuit ratings are higher than the fault levels in the area as shown in Section 4.

-End of Section-

4. Short Circuit Assessment

Fault level studies were completed by the transmitter on behalf of the IESO to examine the effects of the project on fault levels at existing transmission facilities in the surrounding area and the proposed project. Studies were performed to determine the fault levels before and after the incorporation of the project assuming that all existing and committed generators, up to the date of this assessment, were in service. The two 7 MVA synchronous condensers in the proposed project were included in this short circuit study. The short circuit study assumptions are presented in Appendix A.

Table 5 summarizes the fault levels at facilities near the project, before and after the incorporation of the project:

Table 5: Fault levels at facilities near the project

Bus	Before the Project		After the Project		Lowest Rated Circuit Breaker (kA)
	3-Phase	L-G	3-Phase	L-G	
Symmetrical Fault Current (kA)[1]					
Porcupine 500 kV	6.80	7.26	6.85	7.30	63
Porcupine 230 kV	7.34	9.42	7.37	9.44	40
Porcupine 115 kV	11.12	14.50	11.69	14.79	40
Hunta 115 kV	10.11	6.33	10.16	6.34	40
Timmins K23 115 kV	9.69	9.71	9.87	9.83	40
Timmins K1 115 kV	9.70	9.58	9.99	9.77	40
Cote Gold 115 kV	-	-	1.24	0.562	40
Asymmetrical Fault Current (kA)[1]					
Porcupine 500 kV	8.16	9.45	8.22	9.50	81.9
Porcupine 230 kV	9.57	12.88	9.61	12.93	48
Porcupine 115 kV	13.49	18.17	13.77	18.50	48
Hunta 115 kV	10.50	6.66	10.54	6.67	48
Timmins K23 115 kV	10.76	10.67	10.94	10.78	48
Timmins K1 115 kV	10.76	10.45	11.08	10.65	48
Cote Gold 115 kV	-	-	1.53	0.77	40[2]

(1): The results assume a pre-fault voltage level of 550 kV for 500 kV buses, 250 kV for 230 kV buses, and 127 kV for 115 kV buses.

(2): Assumed to be at least the same as symmetrical short circuit capability.

Table 5 shows that the interrupting capabilities of the all circuit breakers at transmission facilities in the vicinity of the project, including the project itself, are adequate for the anticipated fault levels.

– End of Section –

5. Protection Impact Assessment

A Protection Impact Assessment (PIA) was completed by the transmitter to examine the impact of the project on existing transmission system protections.

The addition of the new line T2R from Timmins TS will require new redundant protections at Timmins TS to protect the line, as well as modifications to P13T line protections at both Timmins TS and Porcupine TS. Minor modifications to P15T at Timmins TS protections will be required as well. A copy of the Protection Impact Assessment can be found in Appendix B of this report.

The transmitter must submit any protection modifications that are different from those considered in this SIA at least six (6) months before any modifications are to be implemented on the existing protection systems. If those modifications result in adverse reliability impacts, mitigation solutions must be developed.

– End of Section –

6. System Impact Studies

System impact studies were carried out to identify the effect of the project on the thermal loading of transmission circuits and system voltages for pre- and post- contingency events on the IESO-controlled grid. The impact of the project on power transfer capability measured on transmission interfaces was also studied. A line end opening study and motor starting study at the project were also performed.

6.1 Existing System

The project will be incorporated into the Timmins 115 kV area. The Timmins 115 kV area is located within the Northeast transmission zone and includes the portion of the 115 kV system bounded by the Porcupine 115 kV bus and the Hunta 115kV bus. Circuits within this area include P13T, P15T, P7G, T61S, H6T and H7T.

The loss of the 500 kV circuit P502X can result in the region of the Northeast zone bounded by Hanmer TS and Kirkland Lake TS being subjected to under-voltage, over-voltage, transient instability, relay margin violations and large frequency swings depending on system conditions. As such, there are two interfaces that aid in determining the transfer capability within this specific region: Porcupine Flow North (PFN) and Porcupine Flow South (PFS). Porcupine Flow North is defined as the active power flowing north on circuit P502X out of Hanmer TS plus the active power flowing north on circuits A8K and A9K at Ansonville TS. Porcupine Flow South is defined as the active power flowing south on P502X out of Porcupine TS and the active power flowing south on circuit D3K into Dymond TS.

Historic operation data shows that the maximum Porcupine Flow North value was about 290 MW while the maximum Porcupine Flow South value was about 1200 MW.

A simplified diagram of the Northeast Ontario power system is shown in Figure 3.

The demand in the Timmins area, defined as Timmins Area Load, is the sum of the active power flow out of Hunta SS on H6T and H7T and active power flows out of Porcupine on P13T, P15T and P7G. The loads within the Timmins Area are typically winter peaking.

Local generation in the Timmins 115 kV area consists of embedded generating stations Sandy Falls GS (5.5 MW) and Wawaitin GS (15 MW) at Timmins TS and Lower Sturgeon Falls GS (14 MW) at La Forest Road DS.

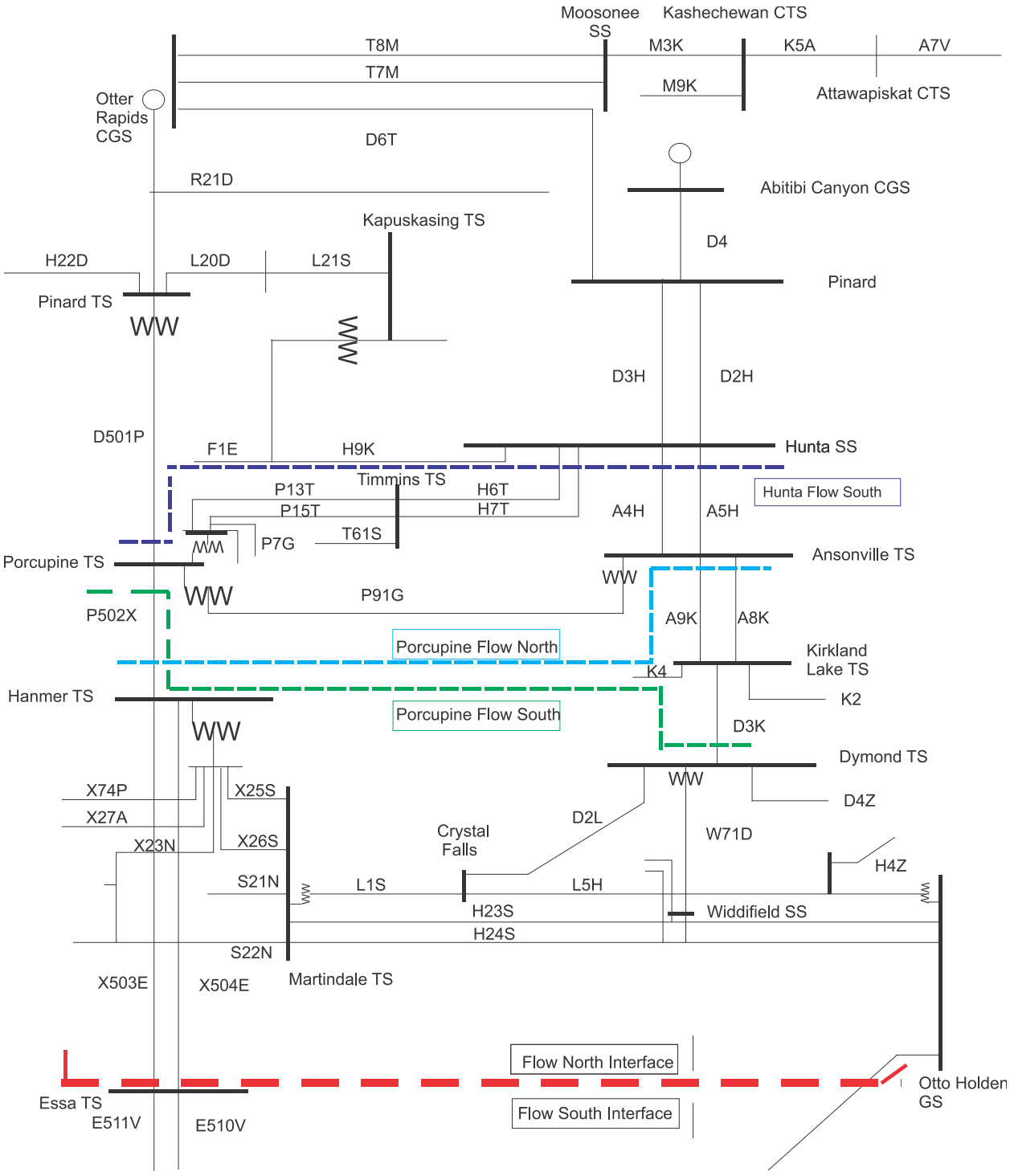

Figure 3: Simplified Diagram of the Northeast Ontario Power System

6.2 Study Assumptions

In this assessment, the following assumptions were used:

(1) **Transmission facilities**: All existing and committed major transmission facilities with 2021 in-service dates or earlier were assumed in-service.

(2) **Generation facilities:** All existing and committed major generation facilities with 2021 in-service dates or earlier were assumed in-service with the exception of Kapsukasing/Ivanhoe generation project (CAA ID 2010-394), which is currently on-hold.

(3) **Load Facilities:** All existing and committed load facilities with 2021 in-service dates or earlier were assumed in-service.

In anticipation of additional load connecting in this area, the project "Timmins West Mine CTS Expansion" (CAA 2015-542), "Bradshaw Gold Project" (CAA2016-579), "Bell Creek CTS – Load Increase" (CAA ID 2017-617) and "Ramore TS – Add new Transformer T2" (CAA 2016-582) were assumed to be in-service for this study.

(4) **Load power factor at the project:** The connection applicant confirmed that the 115 kV power factor at the project will be regulated close to 0.98 lagging as a minimum. Therefore, the power factor was set to 0.98 lagging at the 115 kV side of the project, with proposed SVCs out of service.

(5) **SVC at the project:** For this study, it was assumed that the proposed two +25/-5 Mvar SVCs were placed on each of the project's 13.8 kV buses to maintain the bus voltage at nominal voltage, 13.8 kV.

(6) **Load Forecast:** The study period covers 10 years from the in-service date of the project (2021-2031). The transmitter provided the extreme weather coincident winter peak load forecast for the Timmins area during this period as shown in Table 6 below. The load forecast for Bell Creek CTS is based on the SIA of Bell Creek CTS – Load Increase (CAA ID 2017-617).

Table 6: Winter Peak Load Forecast for Timmins 115 kV Area

Major load station	Winter Peak forecast load (MW)										
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Bell Creek CTS	25	25	25	25	25	25	25	25	25	25	25
Gold Corp Dome CTS	20.2	20.2	20.3	20.3	20.4	20.5	20.5	20.5	20.5	20.5*	20.5*
Goldcorp Hoyle Pond CTS	11.8	11.9	11.9	11.9	12	12	12	12	12	12*	12*
Hoyle DS	8.1	8.2	8.2	8.2	8.2	8.3	8.3	8.3	8.4	8.4	8.4
Kidd Minesite CTS	28.9	29	29	29.1	29.2	29.2	29.2	29.2	29.2	29.2*	29.2*
La Forest Road DS	6.9	6.9	6.9	6.9	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Timmins TS	41.2	41.3	41.3	41.4	41.5	41.6	41.6	41.7	41.8	41.8	41.9
Shiningtree DS	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Weston Lake DS	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Timmins West Mine CTS	13	13	13	13	13	13	13	13	13	13*	13*
Bradshaw Gold CTS	5	5	5	5	5	5	5	5	5	5*	5*
Total	**167.4**	**167.8**	**167.9**	**168.1**	**168.6**	**168.9**	**168.9**	**169**	**169.2**	**169.2**	**169.3**

*: Load forecasts from the customers could not be obtained at the time of the study so these load forecasts are based on historic data.

The summer peak load forecast was not provided by the transmitter. The assumptions used to derive the summer peak load forecast were based on the same assumptions used in the "Timmins West Mine CTS Expansion" (CAA 2015-542) as follow:

(1) The customer transformer station's (CTS) peak loads are not strongly dependent on weather conditions and therefore were assumed to be the same as the winter peak load forecast as shown in Table 6.

(2) The non CTS loads were obtained by scaling down the winter peak load forecast to 90% of the total Timmins 115 kV area peak load; consistent with historical patterns.

The summer peak load forecast is shown in Table 7.

Table 7: Summer Peak Load Forecast for Timmins 115 kV Area

Major load station	Summer Peak forecast load (MW)										
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bell Creek CTS	25	25	25	25	25	25	25	25	25	25	25
Gold Corp Dome CTS	20.2	20.2	20.3	20.3	20.4	20.5	20.5	20.5	20.5	20.5	20.5
Goldcorp Hoyle Pond CTS	11.8	11.9	11.9	11.9	12	12	12	12	12	12	12
Hoyle DS	7.3	7.4	7.4	7.4	7.4	7.5	7.5	7.5	7.6	7.6	7.6
Kidd Minesite CTS	28.9	29	29	29.1	29.2	29.2	29.2	29.2	29.2	29.2	29.2
La Forest Road DS	6.21	6.21	6.21	6.21	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Timmins TS	37.1	37.2	37.2	37.3	37.4	37.4	37.4	37.5	37.6	37.6	37.7
Shiningtree DS	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Weston Lake DS	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Timmins West Mine CTS	13	13	13	13	13	13	13	13	13	13	13
Bradshaw Gold CTS	5	5	5	5	5	5	5	5	5	5	5
Total	**161.1**	**161.4**	**161.5**	**161.7**	**162.2**	**162.5**	**162.5**	**162.6**	**162.8**	**162.8**	**162.8**

(7) **Voltages:** All 115 kV buses within the Northeast zone must respect pre- and post-contingency maximum voltage levels as per the ORTAC with the exception of those buses at the stations shown in Table 8.

The maximum voltage levels at these stations have been provided by the transmitter. The pre-contingency minimum voltage levels at these stations ensure that transfer limits within the Northeast zone are respected.

Table 8: Voltage Ranges for Specific 115 kV buses in the Northeast Zone

Station	Minimum Voltage (kV)	Maximum Voltage (kV)
Abitibi Canyon SS	125	138
Ansonville TS	120	127
Hunta SS	123	138
Kapuskasing TS	113	130
Porcupine TS	125	135
Timmins TS	125	138

(8) **Base Cases:** Since the peak flow south typically occurs during summer conditions and the peak flow north occurs during winter conditions, two base cases were developed corresponding to the winter and summer load conditions and interface transfers. These two cases were used for both thermal and voltage studies.

Winter peak load case

- A Northeast demand of 1,665 MW was assumed, based on the IESO extreme weather winter peak load forecast for the year 2031
- Load level in the Timmins 115 kV area was set to the 2031 winter peak load forecast as shown in Table 6
- PFN interface transfer of 320 MW
- Loads were modeled as constant MVA unless otherwise specified
- A 0.90 lagging power factor was assumed for the loads at all stations in the area unless otherwise specified

Constrained summer peak load case

As indicated in "Timmins West Mine CTS Expansion" (CAA 2015-542) and "Bradshaw Gold Project" (CAA2016-579) SIAs, congestion becomes an issue with heavy flow south on 115 kV circuits H6T and H7T under high generation conditions. As such, an interface, Hunta Flow South (HFS) was defined to monitor the active power flowing south on H6T/H7T and A4H/A5H out of Hunta SS and the active power flowing south on circuit D501P into Porcupine TS. The new defined interface is shown in Figure 3.

To mitigate the overload condition on H6T/H7T, generation within the Northeast zone, i.e. Abitibi Canyon G2 was curtailed. As such, an additional constrained case, called "the constrained summer peak load case", was created to perform the post-contingency analysis with the following attributes:

- A Northeast demand of 1,150 MW, based on the IESO extreme weather summer peak load forecast for the year 2031
- The load level in the Timmins 115 kV area was set to the 2031 summer peak load forecast as shown in Table 7
- The flow on the HFS interface was set to a maximum of 1270 MW corresponding to H7T reaching its continuous rating
- The PFS interface was set to a transfer of 1320 MW
- Loads were modeled as constant MVA unless otherwise specified
- Loads at all stations were set to a power factor of 0.90 in the area unless otherwise specified

6.3 Contingencies

The contingencies simulated in this assessment are in accordance with NERC TPL-001-4 and the ORTAC.

All single element and common tower contingencies in the Timmins 115 kV area were tested. Breaker failure contingencies at Hunta SS, Timmins TS and Porcupine TS were also tested. Finally, under outage conditions, contingencies that would result in additional loading on circuits in the Timmins 115 kV area

were also tested. Table 9 lists all the contingencies simulated for thermal and voltage analyses. It should be noted that any contingency involving P13T results in tripping T2R due to the connection configuration.

Table 9: List of Simulated Contingencies

Contingency	Contingency element(s)
N-1	H6T, H7T, P13T, P15T, P91G, A4H, A5H, Porcupine T3, Porcupine T4
N-2 (tower contingencies or breaker failure)	P13T+P15T H6T+H7T A4H+A5H T2R+T61S Hunta L3L7 BF (Loss of H7T+D3H) Hunta L4L7 BF (Loss of A4H+L8L+H7T) Timmins K3H7T BF (Loss of H7T+P15T+P7G+T61S) Porcupine K1K4 BF (Loss of Porcupine T4, P15T, P7G,T61S)
N-1-1 (outage + contingency)	Porcupine K2K3 + Porcupine K3K4 IBO Hunta L4L6 + Hunta L5L6 IBO Hunta L4L7 + Hunta L3L7 IBO Porcupine T3 + Porcupine T4 P13T + P15T P15T + H6T P13T + H7T H6T + H7T

6.4 Additional Study Assumptions

6.4.1 Northeast Load and Generation Rejection (NE LGR) Scheme

The Northeast Load and Generation Rejection (NE LGR) Scheme, is a Special Protection Scheme (SPS) which trips loads and generation upon detecting certain contingencies within the Northeastern zone of the IESO-Controlled Grid. This scheme was used in this study to manage thermal and voltage concerns following contingencies.

The NE LGR matrix is shown in Table 10. A subset of the NE LGR Scheme matrix that pertains to the Timmins Area Load region is highlighted in grey.

Table 10: Northeast Load and Generation Rejection Scheme Matrix

Control Action	Contingencies																
	D501P	P502X	P91G	L20D/L21S	D2H	D3H	A4H	A5H	A4H+A5H	H6T/P13T	H7T/P15T	H6T+H7T	H9K	Porcupine T3	Porcupine T4	Ansonville T2	Ansonville H1L91 IBO
Reject Abitibi Canyon G2	X	X	X		X	X	X	X	X	X	X	X					
Reject Abitibi Canyon G3	X	X	X		X	X	X	X	X	X	X	X					
Reject TCPL Kapuskasing NUG	X	X		X									X				
Reject Nagagami & Shekak NUG	X	X	X	X									X				
Reject Calstock NUG	X	X	X	X						X	X	X	X				
Reject Long Sault Rapids NUG		X	X					X		X	X	X				X	X
Reject Cochrane Power NUG		X	X				X	X	X	X	X	X				X	X
Reject Tunis NUG		X	X				X			X	X	X				X	X
Reject Iroquois Falls Power CGS G1		X					X	X	X	X	X	X					
Reject Iroquois Falls Power CGS G3		X	X				X	X	X	X	X	X					
Reject Iroquois Falls Power CGS – all		X	X				X	X	X	X	X	X					
Reject NP Kirkland Lake NUG G6		X															
Trip H2O Power Iroquois Falls CTS		X	X				X	X	X	X	X	X					
Trip TMP load at SF Inc.				X													
Trip TMP load at SP Inc.		X															
Trip TMP load at SF Inc.	X																
Trip P7G, P15T, T61S	X	X												X	X		
Trip 27.6 kV breakers at Timmins	X	X												X	X		
Trip H7T	X	X												X	X		
Trip L21S/K38S	X	X		X													
Open A8K and A9K at Ansonville		X															
Open H9K at Hunta	X	X		X													
Trip P91G	X	X	X														

Trip Detour Gold Sag and Ball #1	X	X														
Trip Detour Gold Sag and Ball #2	X	X														
Trip Entire Detour Gold Facility	X	X														
Trip Northland Power Solar Farms		X	X			X	X	X	X	X	X	X				X	X

6.4.2 Proposed Tie Switch at Timmins TS

During an outage of P13T, circuits T2R and H6T are connected radially to Hunta SS and the load at the proposed project cannot be supplied due to voltage collapse. It can be mitigated by installing a normally open tie switch between the two Timmins 115 kV buses and closing the switch during an outage of P13T.

Simulation results show the current on the tie switch can be up to 370 A when it is closed during an outage of P13T. The transmitter confirmed they will install a normally open load interrupting switch between the two Timmins 115 kV buses and close the switch during an outage of P13T to maintain Timmins TS voltage above its pre-contingency minimum voltage.

In this study it is assumed that there is a tie switch between the two Timmins 115 kV buses closed for an outage of P13T. Figure 4 shows simplified Timmins 115 kV system with the proposed tie switch.

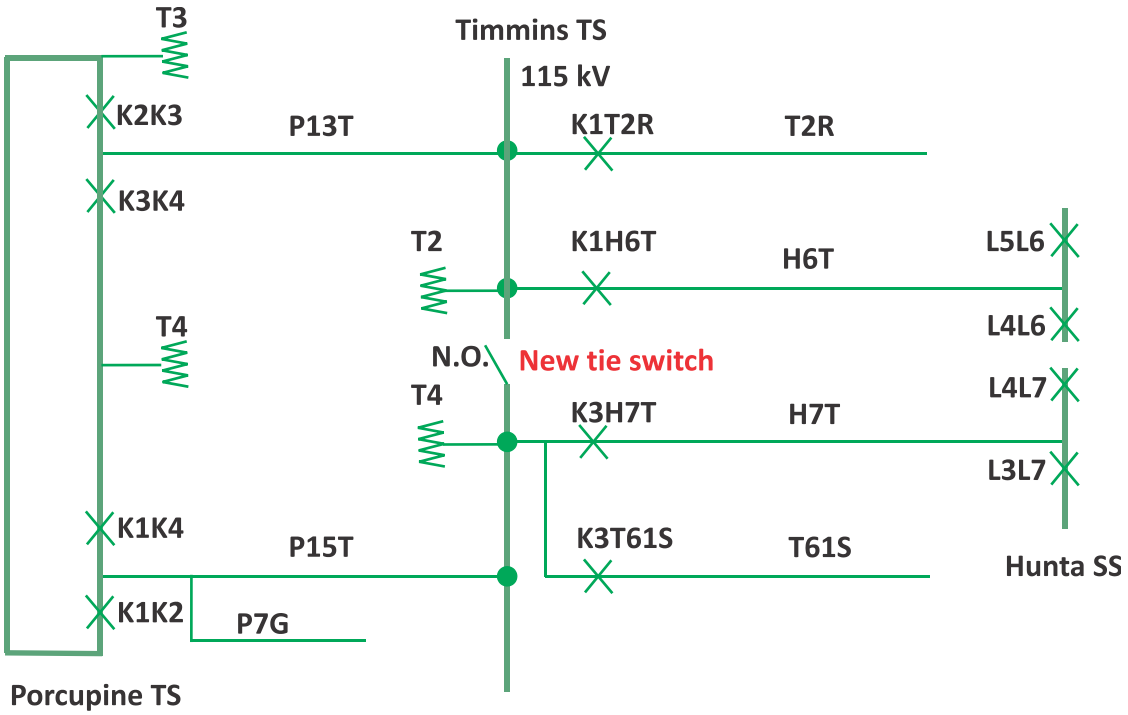

Figure 4: Simplified Diagram of Timmins 115 kV System with the Proposed Tie Switch

6.5 Thermal Analysis

The ORTAC specifies the following criteria for thermal loading of transmission facilities:

(1) Continuous ratings are used for pre-contingency equipment loading with all planned transmission facilities in-service,

(2) Long-term emergency (LTE) ratings are used with any one element out of service (planned or unplanned), and

(3) Short-term emergency (STE) ratings are used with more than one element out of service (unplanned).

Where circuits and transformers may be loaded up to their STE ratings, system adjustments must be available to reduce their loading to within the LTE ratings within the time afforded by their STE ratings.

Thermal analysis was performed to ensure that the local transmission system meets the criteria prescribed by the ORTAC after the project is incorporated. Table 11 lists the thermal ratings of the monitored circuits and transformers. The ratings were provided by the transmitter with the exception of the ratings for T2R from Shiningtree to the project. Those ratings were provided by the connection applicant.

Table 11: Circuit Section and Transformer Ratings

	From	To	Rating (A)					
			Continuous[3]		LTE[3]		STE[3]	
			Summer[1]	Winter[2]	Summer[1]	Winter[2]	Summer[1]	Winter[2]
H6T	Hunta SS	Bradshaw junction	500	580	530	610	530	610
	Bradshaw junction	Tisdale junction	500	580	530	610	530	610
	Tisdale junction	Laforest Road junction	500	580	530	610	530	610
	Laforest Road junction	Timmins TS	500	580	530	610	530	610
H7T	Hunta SS	Warkus junction	500	580	530	610	530	610
	Warkus junction	Timmins TS	500	580	530	610	530	610
P91G	Erg Resources junction	Porcupine TS	1120	1300	1440	1580	1680	1800
	Hoyle junction	Erg Resources junction	1120	1300	1440	1580	1680	1800
	Ansonville junction	Hoyle junction	1120	1300	1440	1580	1650	1780
	Ansonville TS	Ansonville junction	1120	1300	1440	1580	1650	1780
P13T	Porcupine TS	Timmins TS	890	1030	1060	1180	1150	1260
P15T	Porcupine TS	Timmins TS	890	1030	1140	1250	1250	1360
T2R	Timmins TS	Shiningtree junction	670	780	850	850	920	920
	Shiningtree junction	Cote Gold Project	1040	1200	1266	1387	1266	1387
T2	Ansonville TS (115 kV)	Ansonville TS (230 kV)	125	125	260.3	267	267 1	267
T3	Porcupine TS (500 kV)	Porcupine TS (115 kV) Porcupine TS (27.6 kV)	225	225	225	246	332.8	374.6
T4	Porcupine TS (500 kV)	Porcupine TS (115 kV) Porcupine TS (27.6 kV)	225	225	225	246	332.8	374.6

Notes: (1) Summer ambient conditions: 30°C temperature, 4 km/h wind speed, daytime
(2) Winter ambient conditions: 10°C temperature, 4 km/h wind speed, daytime
(3) Continuous: Rating calculated at the lesser conductor temperature of 93°C or sag temperature
Long term emergency: Rating calculated at lesser conductor temperature of 127°C or sag temperature
Short term emergency: Rating calculated at the sag temperature with a pre-contingency loading of 100% of the continuous rating
For transformers LTE and STE mean 10-day and 15-minute thermal ratings, respectively.

6.5.1 Winter Peak Load Case

For all studies using the winter peak load case with high PFN transfer, no thermal violations occurred on the monitored elements pre- and post-contingency. However, for the loss of Porcupine transformer T3 or T4, the remaining transformer loading becomes 105% of the transformer's continuous rating which corresponds to 96% of the transformer's winter 10-day LTE.

6.5.2 Constrained Summer Peak Load Case

Power transfer capabilities on Hunta Flow South interface before and after the proposed project were studied. It was found that the power transfer capability on this interface decreases 1.3% which is less than 5%, meeting the ORTAC requirement.

Loss of one element (N-1) and Loss of two elements (N-2)

For studies with all elements in-service, loss of one element (N-1) and loss of two elements (N-2) using the constrained summer peak load case, results show that all post-contingency loadings were within their LTE ratings for the loss of one element.

Loss of one element under outage condition (N-1-1)

For the constrained summer peak load case, an outage of Hunta L4L6 followed by an L5L6 IBO results in the H6T line end opening at Hunta and the loading on H7T above its LTE ratings. Similarly, H6T is overloaded during an outage of L4L7 followed by an L3L7 IBO. These are existing issues and the proposed project makes the overloading conditions worse. The overloading results are shown in Table 12. The issue can be managed by curtailing the generation output during the outage of the aforementioned breakers.

Currently, detection logic in the NE LGR scheme for contingencies involving H6T or H7T is defined as breaker K1H6T or K3H7T open at Timmins. It is recommended that the transmitter include the opening of Hunta SS 115 kV breakers L4L6+L5L6 and L3L7+L4L7 as part of the detection logic for circuits H6T and H7T, respectively, to mitigate the overload issues described above.

Table 12: Post-contingency load flow (L4L6/L3L7 O/S and L5L6/L4L7 IBO)

Element	Circuit Section		LTE	L4L6 O/S	L3L7 O/S
	From	To	A	L5L6 IBO	L4L7 IBO
P13T	PORCUPINE	TIMMINS	1150	38.90%	38.00%
P15T	PORCUPINE	TIMMINS	1250	39.80%	13.00%
H6T	TIMMINS	LAFOREST_RDJ	530	0.00%	122.90%
	LAFOREST_RD	TISDALE_J	530	0.00%	126.40%
	TISDALE_J	BRADSHAW_JT	530	0.00%	126.50%
	BRADSHAW_J	HUNTA_SS	530	0.00%	130.40%
H7T	TIMMINS	WARKUS_J	530	115.10%	0.00%
	WARKUS_J	HUNTA_SS	530	132.50%	0.00%
P91G	PORCUPINE	ERG_RES	1680	36.40%	36.60%

	ERG_RES_J	HOYLE	1680	36.40%	36.60%
	HOYLE_J	ANSON	1650	36.90%	37.00%
T2R	TIMMINS	SHINGTR	920	40.20%	40.50%
	SHINGTR	COTE GOLD	1266	29.10%	29.20%

6.6 Voltage Analysis

Sections 4.2 and 4.3 of the ORTAC state that with all facilities in-service pre-contingency, the following criteria shall be satisfied:

- The pre-contingency voltages on 500 kV buses must not be less than 490 kV and no greater than 550 kV, 230 kV buses must not be less than 220 kV and no greater than 250 kV and 115kV buses must not be less than 113 kV and no greater than 127 kV;
- The post-contingency voltages on 500 kV buses must not be less than 470 kV and no greater than 550 kV, 230 kV buses must not be less than 207 kV and no greater than 250 kV and 115 kV buses must not be less than 108 kV and no greater than 127 kV; and
- The voltage change following a contingency must not exceed 10% pre-ULTC and 10% post-ULTC on 500 kV, 230 kV and 115 kV buses.

The voltage performance of the IESO-controlled grid was evaluated by examining if pre- and post-contingency voltage levels and post-contingency voltage declines remain within criteria prescribed by the ORTAC at stations in the vicinity of the project. Table 13 lists the buses that were monitored.

Table 13: List of Monitored Buses

Monitored Buses
Porcupine TS 500 kV
Porcupine TS 230 kV
Porcupine 115 kV
Ansonville TS 230 kV
Ansonville TS 115 kV
Hunta SS 115 kV
Timmins K1 115 kV
Timmins K3 115 kV
Shiningtree T61S 115 kV
Shiningtree T2R 115 kV
Project 115 kV
Project 13.8 kV

Studies indicated that with the two proposed +25/-5 Mvar SVCs in-service, the pre-contingency voltages can be maintained above the minimum requirements by the ORTAC.

In the winter and summer constrained base cases the loss of the proposed SVC(s) results in the post-contingency voltage at the project's 115 kV bus below the 108 kV minimum required by the ORTAC. To mitigate this issue, the connection applicant is proposing to implement a load rejection scheme that rejects the project's load upon the loss of the SVC(s).

The connection applicant is required to provide a detailed description of the load shedding scheme during the Market Registration process.

As per Section 6.4, the proposed 115 kV normally open bus tie switch at Timmins TS is assumed closed during outage of P13T in this study.

6.6.1 Winter Peak Load Case

Loss of one element (N-1) and Loss of two elements (N-2)

For studies with all elements in-service, loss of one element (N-1) and loss of two elements (N-2) using the winter peak load case with high PFN transfer, the voltages at monitored buses in

Table 13 were found to be within criteria.

Loss of one element under outage condition (N-1-1)

For the loss of both circuit breakers K2K3 and K3K4 at Porcupine TS, circuits P13T and T2R are connected radially to Hunta TS through H6T which results in voltage collapse at the proposed project.

Furthermore, under an outage of Porcupine T3, a Porcupine T4 contingency results in voltage collapse at the proposed project.

To address the above issues, the transmitter is required to implement an SPS to trip the proposed project upon the loss of both circuit breakers K2K3 and K3K4 or the loss of T3 and T4 at Porcupine. Details on SPS implementation are given in Section 6.10.

Under an outage of P13T, a P15T contingency results in the loss of Timmins T2 and T4, T2R, T61S and P7G. The post-contingency voltage at the Porcupine 500 kV bus is about 553 kV as shown in Table 14. The maximum post-contingency voltage at Porcupine 500 kV bus as specified by the owner is permitted to be as high as 555 kV. Therefore, there is no concern.

Table 14: Voltage Results for P13T O/S and Loss of P15T

Bus Name	Base kV	Pre Cont	Loss of P15T_P13T OS			
			Pre ULTC		Post ULTC	
		Volt kV	Volt kV	% Change	Volt kV	% Change
PORCUPINE_TS500.00	500	534.4	552.6	3.4%	553.1	3.5%
PORCUPINE_TS220.00	220	242.0	249.2	3.0%	242.5	0.2%
PORCUPINE_TS118.05	118.05	128.7	136.9	6.4%	132.4	2.9%
ANSONVILLE 220.00	220	245.4	250.4	2.1%	245.3	0.0%
ANSONVILLE 118.05	118.05	122.8	124.1	1.1%	122.3	-0.4%
HUNTA_SS 118.05	118.05	128.3	128.0	-0.2%	126.8	-1.2%
TIMMINS_K1H6118.05	118.05	127.6	0.0	-	0.0	-
TIMMINS_K23 118.05	118.05	127.6	0.0	-	0.0	-
SHINGTR_T61S118.05	118.05	127.6	0.0	-	0.0	-
SHINGTR_T2R 118.10	118.1	118.2	0.0	-	0.0	-
COTEGOLD 118.10	118.1	118.3	0.0	-	0.0	-
COTE_T1 13.800	13.8	13.8	0.0	-	0.0	-

6.6.2 Constrained Summer Peak Load Case

For studies with all elements in-service, loss of one element (N-1) and loss of two elements (N-2) using the constrained summer peak load case, the voltages at monitored buses in Table 13 were found to be within criteria.

For the loss of one element under outage conditions, the same issues were identified as those found in the winter peak load case study and the same solutions proposed in Section 6.10 will address these issues.

6.7 Line End Opening Study

Simulations were performed to investigate potential high voltage at the project resulting from the charging of the 115 kV T2R circuit with the line end opened at the project. The voltage at Timmins was set to its maximum continuous voltage of 138 kV as indicated in Table 8. Simulation results showed that the voltage at the end of T2R is 141.2 kV when energized with no load present. This is about 3 kV higher than the maximum continuous voltage allowed at Timmins. Further simulation showed that to avoid

exceeding 138 kV on equipment connected to circuit T2R, a 6 Mvar reactor rated at 138 kV must be installed at the project's 115 kV bus. The reactor must be on for energizing the T2R circuit and off when the load at the proposed project is in service. The simulation results are shown in Table 15 below.

Table 15: Line End Opening Study Results

	Timmins (kV)	Shiningtree Jct (kV)	Cote Gold (kV)
Line end opening	138	141.0	141.2
6 Mvar Reactor at project	138	137.5	136.5

6.8 Motor Starting Study

The Motor start study was performed on the largest Direct On-Line (DOL) motor. The largest DOL motor at the facility is 800 HP. It was assumed to have 6.5 times full load motor current at 0.2 pf. The load was assumed to be 50 MW when one of the 800 HP motors is starting. The proposed two +25/-5 Mvar SVCs were assumed in-service during motor start.

The motor start study results are shown in Table 16.

Table 16: Motor Start Study Results

	Pre-Start (kV)	Post-Starting (kV)	Voltage Dip (%)
115 kV bus	125.7	122.7	-2.38
13.8 kV bus	13.9	13.4	-3.59

The voltage flicker criteria as per Appendix 2 of the Transmission System Code states that a voltage flicker should be limited to 3% for switching operations performed 4 times per day. A higher voltage change may be acceptable for infrequent motor starts. It was assumed that motors at the proposed project would start only once per day and hence a voltage change limited to 4% was deemed acceptable. For more frequent starts, a more stringent voltage criteria would be applied.

6.9 Total Load Tripped by Configuration Assessment

As per 7.1 Load Security Criteria specified in ORTAC, the maximum load interrupted by configuration should not exceed 150 MW and 600 MW for the loss of one element and two elements, respectively.

To assess these criteria after the incorporation of the project, the total amount of load tripped by configuration for the loss of one or two elements involving the project was examined.

Loss of one element: Based on the winter peak load forecast, a maximum of 72 MW could be interrupted for the loss of one element (loss of T2R) with the project incorporated. The total load lost is within the criteria.

Loss of two elements: Under an outage of P13T, a contingency involving P15T results in the loss of Timmins T2 and T4, and circuits T2R, T61S and P7G. Based on the winter peak load forecast, a

maximum of 205 MW could be interrupted. With the project incorporated, the total load lost is within the criteria.

6.10 Special Protection Scheme

The Northeast Load and Generation Rejection (NE LGR) scheme, currently classified as NPCC type III, was installed to increase the transfer capability in the NE zone during outages to 500 and 230 kV circuits. This is done by cross tripping certain 115 kV circuits and rejecting specific generation and loads. Customers participating in the load rejection function of the NE LGR scheme are exposed to a higher risk of interruption than other customers in the NE zone.

Adding new load to the NE zone increases the likelihood of arming the NE LGR scheme. To ensure that the customers already participating in the load rejection function of this scheme will not be exposed to additional risk as a result of the project, the project must participate in the load rejection portion of the NE LGR scheme or participate in a local load rejection scheme.

According to the results from this SIA study, the proposed project should be rejected for the loss of 500 kV circuits D501P, P502X, Porcupine autotransformer T3 or T4, and opening of K2K3 and K3K4 at Porcupine TS. There are two options to implement rejection for the proposed project: (a) Expanding the existing NE LGR scheme to include rejecting the proposed project, provided that the expanded SPS remains as Type III SPS; or (b) Creating a new Cote Gold SPS. The proposed SPS selection matrix for rejecting the proposed project is shown in Table 17.

Table 17: SPS Selectivity requirements for options (a) and (b)

Control Actions	Contingencies				
	D501P	P502X	Porcupine T3	Porcupine T4	K2K3 and K3K4) at Porcupine
Trip Cote Gold breaker(s)	X	X	X	X	X

The final decision on the option chosen for rejection will depend on further investigation and study by the IESO and the transmitter.

Based on the study results, it is not expected that the failure of either option will result in an adverse impact on Ontario's interconnections. Therefore, it is expected that if option (a) is chosen the NE LGR scheme will remain NPCC type III. If option (b) is chosen the new SPS will also be classified as NPCC type III. However, as required in ORTAC, an SPS proposed in a connection assessment must have full redundancy and separation of the communication channels, and must satisfy the requirements of the NPCC Type I SPS criteria. This means special protection system facilities must be installed at the project to accept a single pair (A & B) of L/R signals, and disconnect the project from the IESO-controlled grid with no intentional time delay when armed following specific contingencies. The special protection system facilities at the project must be built as Type I special protection systems to the extent possible.

If option (b) is chosen, it's recommended that all of the existing functionalities of the NE LGR that are specific to the Timmins area be transferred to the proposed SPS. The transmitter will need to ensure that operation of all transferred functionalities do not take longer in the new scheme as compared to the NE LGR scheme.

A matrix of the recommended SPS is shown in Table 18.

Table 18: Recommended SPS Matrix

Control Actions	Contingencies				
	D501P	P502X	Porcupine T3	Porcupine T4	K2K3 and K3K4) at Porcupine
Trip P7G, P15T, T61S	X	X	X	X	
Trip 27.6 kV breakers at Timmins	X	X	X	X	
Trip H7T	X	X	X	X	
Trip Cote Gold breaker(s)	X	X	X	X	X

-End of Section-

Appendix A: Assumptions for short circuit study

Assumptions for Short Circuit Study

1) Existing Generation Facilities

Northwest				
Name	**Units/Capacity**		**Name**	**Units/Capacity**
Atikokan TGS	G1		Caribou Falls	G1-G3
Thunder Bay	GS2-GS3		Ear Falls	G1-G4
West Coast	G2		Kenora GS	G1-G10
Greenwich Wind	98.9 MW		Manitou Falls	G1-G5
Terrace Bay Pulp	STG1		Norman GS	G1-G5
Umbatta Falls	G1-G2		Pine Portage	G1-G4
Murillo_DSB1	G1-G4		Silver Falls	G1
Aguasabon	G1-G2		Sturgeon Falls	G1-G2
Alexander GS	G1-G5		Whitedog Falls	G1-G3
Wawatay	G1-G3		Valerie Falls	G1-G2
Calm Lake	G1-G2		Lac seul GS	G1
Cameron Falls	G1-G7		Atlantic Power Nipigon	G1-G2
ResFP Kraft and ResFP Thunderbay	G3, G5, G6		Lower White River CGS	G1-G3
			Upper White River CGS	G1-G3

Northeast				
Name	**Units/Capacity**		**Name**	**Units/Capacity**
Iroquois Falls Power CGS	101, 102, 103		Serpent CGS	G1-G2
H2O Power Iroquois Falls	G4		Wells GS	G1-G2

Northland Power Kirkland Lake CGS	G1-G6		Wawaitin GS	G1-G2
Coniston	G1-G3		Domtar Espanola	G1, G2, G5
Atlantic Power Calstock	G1		Tembec (Mallete Kraft)	G1-G2
Atlantic Power North Bay	G1, G2		Nagagami&Shekak	G1-G2
Hound_chuteg	G1-G2		Long Sault	G1-G4
Sandy Falls	G1		High Falls	G1-G2
Lower sturgen	G1-G2		Rayner	G1-G2
Aubrey Falls	G1-G2		Red Rock Falls	G1-G2
Aux Sauble GS	G1		Atlantic Power Kapuskasing	G1-G2
Abitibi Canyon GS	G1-G5		Atlantic Power Tunis	G1-G2
Carmich Falls	G1-G2		Harmon	G1-G2
Crystal Falls	G1-G4		Otto Holden GS	G1-G8
Lower Notch	G1-G2		Kipling GS	G1-G2
Otter Rapids	G1-G4		Little Long GS	G1-G2
Cochrane Power CGS	G1, G2		Mcleans Mountain WGS	59.4 MW
Liskeard Solar	30 MW		Abitibi CGS	10 MW
Lower Mattagami Expansion			Martins Meadows CGS	10 MW
Empire CGS	10 MW		Long Lake CGS	10 MW
Smoky Falls 2 GS	G1-G3			

Essa				
Name	**Units/Capacity**		**Name**	**Units/Capacity**
York Energy Centre	G1, G2		Des Joachims	G1-G8

Toronto				
Name	**Units/Capacity**		**Name**	**Units/Capacity**
Pickering units	G1, G4-G8		Sithe Goreway	G11-13, G15
Darlington	G1-G4		TransAlta Douglas	G1-G3
Portlands GS	G1-G3		GTAA	G1-G3
Algonquin Power (Embedded under Bramalea TS)	G1, G2		Brock west	G1
Whitby Cogen	G1			

Northeast/GLP				
Name	**Units/Capacity**		**Name**	**Units/Capacity**
Lake Superior Power	GTG1, GTG2, STG1		Holingsworth	G1
Prince I & II WGS	198 MW		McPhail	G1-G2
Clergue	G1-G3		Scott	G1-G2
Algoma Steel	103 MW EG		Mission Falls	G1
Gartshore	G1		Harris GS	G1
Hogg	G1		Steep Hill Falls	G1
Andrews GS	G1-G3		Mackay GS	G1-G3
GOULAIS WGS	25 MW		Bow Lake CGS	20 MW
Bow Lake 2 CGS	40 MW			

2) Committed Transmission Connected Generation Projects

Without SIA/CIA application

Zone	Project Name	Proposed Size	Connection Point	Gen Type
East	Barlow Solar Energy Centre	10	ST LAWRENCE TS	**Distribution**
Ottawa	Pendleton Solar Energy Centre	12	WENDOVER DS	**Distribution**

Essa	Sky One (Solar)	11.76	MUSKOKA TS	**Distribution**

With SIA/CIA application

Zone	6.10.127 Project Name	CAA ID	Generation Type	Capacity	I/S Date
Northeast	Yellow Falls (previously called Island Falls)	2004-155	Hydroelectric	16.4MW	2017/9/30
	Kabinakagami Generation Development	2010-389	Hydroelectric	26MW	Unknown
	New Post Creek GS (Peter Sutherland Sr GS)	2007-294	Hydroelectric	28.8MW	2017/04/01
	Smooth Rock Falls GS (Mallette Kraft CGS)	2014-518	Hydroelectric	9.2 MW	2016/12/30
Northwest	Wawatay G4	2004-130	Hydroelectric	7MW	2019/1/1
	Trout Lake River Small Hydro Project	2010-390	Hydroelectric	3.75MW	2017/2/28
	Namewaminikan Hydro project	2010-393	Hydroelectric	6.4MW	2017/05/31

3) Load Projects or Customer's synchronous motors or generators

Existing Stations with Synchronous Motors or Generators

Zone	*Station*	Voltage (kV)	MVA
Northwest	Domtar Dryden CTS	13.2	20.65
	Dryden Weyerhauser	13.2	41.9
	Fort Francis TS	13.8	35.05
	Kenora	6.6	80
	Kenora CGS	2.4	12.5
	Lac Des Iles Mine (Syn. Motors)	4.16	23.8
	Marathon Pulp CTS (Syn. Motors)	4.16	1.9
	Murillo DS	25	28.6
	Norman CGS	6.6	16.5
	ResFD Kraft CTS	13.8	38
	ResFD Thunder Bay CTS	4.16	19
		13.8	230.46
Northeast	Espanola TS	44	11.62
	Tembec Kapuskas CTS	13.8	47.74

	Tembec Spruce Falls	13.8	23.87
		6.6	100.71
	Cote Gold	13.8	14

Existing Station with Transformer configuration of Yg/Δ or Yg/Yg/Δ

Zone	Project Name	CAA ID	Transformer
Northeast	Detour Lake 230 kV	2009-359	T1, T2, T3

Committed Stations with Synchronous Motors or Generators

Zone	Project Name with Connected Station	CAA ID	Voltage (kV)	MVA
Northwest	Marathon PGM (Syn. Motors)	2012-476	13.8	30.6
	Esker CTS - Synchronize Diesel Generators	2016-EX841	4.16	9.12
Northeast	Upper Beaver Mine and Mill Complex (Syn. Motors)	2012-482	25	22.22
Northeast	Domtar Espanola CGS	2015-558	13.8	30 MW

Committed Stations with Transformer configuration of Yg/Δ or Yg/Yg/Δ

Zone	Project Name	CAA ID	Transformer
Northwest	Rainy River	2013-502	T1, T2
Northeast	New Hanmer Load Station	2016-560	T1, T2

Committed Stations with Synchronous Motors and Transformer configuration of Yg/Δ or Yg/Yg/Δ

Zone	Project Name	CAA ID	Voltage (kV)	MVA	Transformer
Northwest	Osisko Hammond Reef Gold Mine	2012-470	27.6	44	T1, T2

4) Transmission System Upgrades

Zone	Project Name	CAA ID	Descriptions
Northwest	TransCanada Energy East	2013-492	Connecting 2 new circuits between: M2D and S1C, A4L and M2W.
	Ontario 230 kV East-West Tie	2016-568	Connecting new 230 kV circuits M37L and M38L between Lakehead TS and Marathon TS; 230 kV circuits W35M and W36M between Marathon TS and

			Wawa TS.
	Wataynikanepay Transmission	2016-567	To build a new 230 kV transmission line between the 230 kV circuit D26A, and the 115 kV circuit E1C.
Toronto	Clarington TS	2012-462	500/230kV switching and transformer station to be established at the existing Oshawa Area Junction on the Bowmanville TS by Cherrywood TS transmission line corridor
	Runnymede TS (KxW upgrade) project	2016-571	New DESN along with upgrading K1W, K3W, K11W and K12W
Essa	Barrie Area Reinforcement project	2016-580	Uprate E3/4B to 230 kV circuits and rebuild Barrie TS

Appendix B: PIA Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

PROTECTION IMPACT ASSESSMENT

IAMGOLD – COTE LAKE MINE CONNECTION R1

SUMMARY

PCT – 925

Date: February 21, 2018

Disclaimer

This Protection Impact Assessment has been prepared solely for the IESO for the purpose of assisting the IESO in preparing the System Impact Assessment for connection of the proposed transmission facilities to the IESO–controlled grid. This report has not been prepared for any other purpose and should not be used or relied upon by any person for any other purpose.

This Protection Impact Assessment was prepared based on information available to Hydro One at the time the assessment was carried out. It is intended to highlight significant impacts, if any, to affected transmission protections early in the project development process. The results of this Protection Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or legal requirements. In addition, further issues or concerns may be identified by Hydro One during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with the Transmission System Code legal requirements, and any applicable reliability standards, or to accommodate any changes to the IESO-controlled grid that may have occurred in the meantime.

Hydro One shall not be liable to any third party, which uses the results of the Protection Impact Assessment under any circumstances, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

Revision History

Revision	Date	Change
R0		Initial Release
R1	21/02/18	Change of configuration; addition of bus tie device

PIA – IAMGOLD – COTE LAKE MINE CONNECTION Revision: R1

1 INTRODUCTION

1.1 GENERAL

This PIA study is prepared for the IESO to assess the potential impact of the proposed wind connections from National Rise to the existing transmission protections. The primary focus of this study is to protect Hydro One system equipment while meeting IESO's System Reliability Criteria.

2 DESCRIPTION OF EXISTING AND PROPOSED RECONFIGURATION

Iamgold Corp will be developing a 72MW gold mine located 25km southwest of Gogama, Ontario. To supply this new mine, the idle T2R circuit will be re-energized at 115kV from Timmins TS to Shiningtree junction (approximately 115km in length). A new 44km circuit will then be built from Shiningtree JCT to the customer substation which will be constructed and owned by the proponent (Iamgold). In addition, a new station termination will be required at Timmins TS to accommodate the new T2R circuit in the 115kV yard.

A load break bus tie switch will be added between P13T and P15T. This will allow either line to supply the connecting lines at Timmins should either P13T or P15T be out of service. In order to maintain appropriate line zoning a freestanding CT with 4 cores will be required to be installed at the point of bus connection.

Note: The new 44km line from Shiningtree x Customer CTS will be built, and owned by the customer.

PIA – IAMGOLD – COTE LAKE MINE CONNECTION

Revision: R1

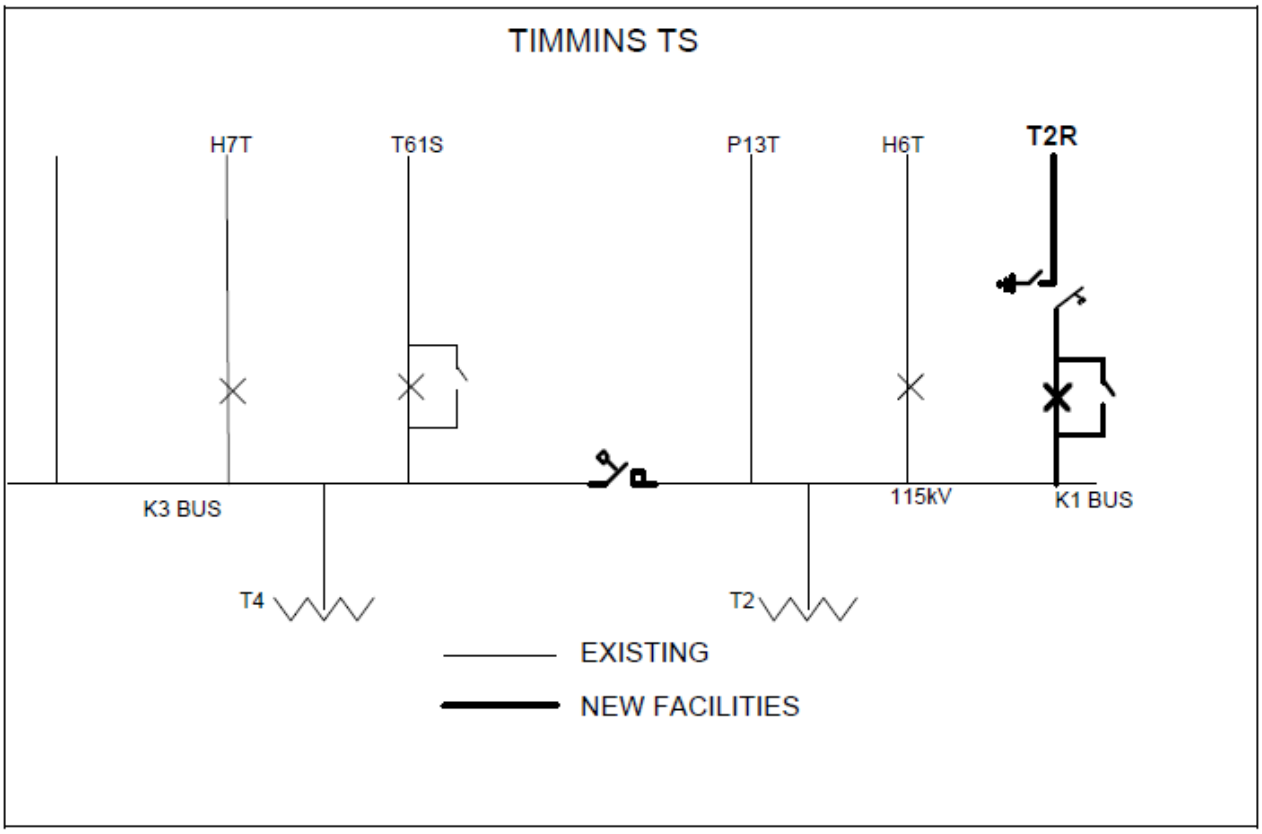

Figure 1: Timmins TS New facilities required for T2R circuit

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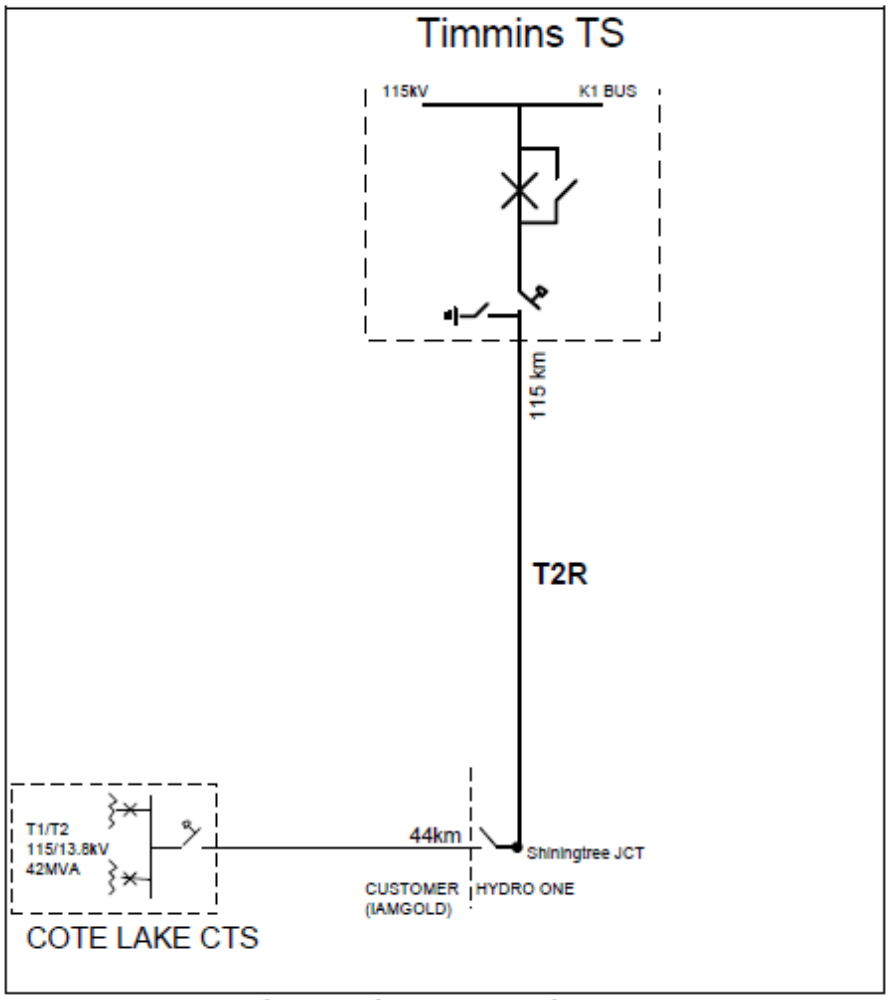

Figure 2 : Connection of Cote Lake CTS to Hydro One Transmission System

2.1 115KV LINE T2R, 115KV LINE P13T LINE P15T

T2R will become a 159km radial line from Timmins TS (115km existing and 44km to be built). There will be 2 operation conditions for this new line.

- Operating Condition 1: The new breaker in service and the T2R line operates as a radial line with its own protection.
- Operating Condition 2: New breaker bypassed with T2R protection blocked. In this situation the new T2R line will be protected by the Group 2 settings of line P13T (the line which will be feeding T2R).

There are no existing settings for T2R.

P13T is a 4.5km line which uses direct underreaching Zone 1 and a permissive overreaching pilot scheme for the zone 2. The settings are set at 75/80% of line impedance for zone1 (ground/phase)

and 125% of line impedance for the zone 2 settings. A reverse Zone 3 is only used locally to supervise fast zone 2 trip. In addition to the pilot scheme which will offer fast tripping, there is a 400ms time delay with the same setting which will trip the local breaker.

3 PROPOSED PROTECTION & TELEPROTECTION SCHEME

3.1 GENERAL

The addition of the new line T2R from Timmins TS will require new redundant protections at Timmins TS to protect the line, as well as modifications to P13T line protections at both Timmins TS and Porcupine TS. Minor modifications to P15T at Timmins TS protections will be required as well.

3.2 ASSUMPTIONS

- As per IESO, the bus-tie is used to provide voltage support when P13T or P15T is out-of-service.
- The proponent will not tie the LV of the transformers with both transformers in service.
- No non-standard operating configurations will be allowed during the bus tie closure.
    - Breaker bypass K3T61S-S for T61S shall be open
    - New breaker bypass for T2R shall be open

3.3 SPECIFIC PROTECTION REQUIREMENTS

3.3.1 Timmins TS and Porcupine TS

- T2R (Operating Condition 1)
    - Install redundant (A and B) protections for line T2R
    - There shall be 2 zones of protection. The zone 1 shall be set to 80/75% (phase/ground) of the positive sequence line impedance and shall instantaneously trip. The zone 2 impedance shall be set to 125% of the positive sequence of the line. The fast zone 2 trip shall be delayed by 50ms to ensure a block signal not to arrive from the customer site.
    - There will be a timed zone 2 protection will be set with 400ms.
    - With the zone 2 settings the protection will see into approximately 70% of the transformer impedance, therefore a blocking signal will be required.
        - IamGold will be required to provide a reverse looking zone element which shall instantaneously send a block signal when a fault occurs within the customer's facility
    - Block and transfer trip shall brought to Timmins TS T2R protections for Operating Condition 1.
- Line P13T (Operating Condition 1: Timmins TS and Porcupine TS)
    - Zone 1 at Timmins TS will be delayed. As Timmins is a weak source it leads to a very low voltage even for out of zone faults, and the CVT error could be great

enough at such low voltages to cause zone 1 overreaching. The delay will be 150ms.
    - P13T will be modified to a DCB scheme. The settings shall remain the same as standard POTT scheme. The existing zone 3 shall be modified to send a block signal to the opposite line end.
    - A and B protections will connect to the new freestanding CT on the bus connection. This will overlap and zone the line protections between P13T and P15T, and will ensure that no settings changes will be required for the specific operating conditions that would allow the bus tie to be closed.
    - Cross-tripping shall be enabled when the bus-tie is closed.
    - CTs on T2R line side from the new T2R breaker shall be brought into the P13T protection so that T2R will be appropriately zoned off from P13T line protection when new breaker is in service. The CTs will be appropriately bypassed in operating condition 2.
- Line P13T (Operating Condition 2: Timmins TS and Porcupine TS).
    - Group 2 shall be a DCB scheme and will be employed only during Operating Condition 2.
    - Block and transfer trip shall brought to Timmins TS P13T protections for Operating Condition 2.
    - At Timmins TS the Group 2 Zone 1 settings shall be the same as the Group 1 Zone 1 setting.
    - As Porcupine is significantly stronger source than Timmins, Timmins TS will experience much higher apparent impedance than Porcupine when a fault occurs on the T2R line. It is not secure to set Timmins zone 2 to the required size due to risk of over-tripping and therefore sequential tripping shall be utilized. IE For most faults on T2R in this condition Porcupine will trip first followed by Timmins. This sequential tripping only occurs for faults on the T2R portion of the line when there is also loss of Transfer Trip from Porcupine. When TT channel is normal, a transfer trip signal will be sent from Porcupine to Timmins.
    - Zone 2 setting at Porcupine TS shall be set to see 125% of the maximum apparent impedance at the customer's HV connection. Tripping shall be delayed 80ms to ensure that no block signal will arrive from Timmins TS or the customer station.
        - The block from the customer station must be cascaded through Timmins TS in Operating Condition 2 (Group 2)
    - Zone 2 at Timmins TS shall be set for 125% of the positive sequence of the line T2R. Due to the high apparent impedance this will only pick up after Porcupine TS has cleared. The zone 2 will be delayed 50ms to ensure no block is received from Porcupine TS or the customer station.
    - The timed zone 2 settings for both Porcupine and Timmins shall be set to 2s as opposed to the standard 400ms in order to coordinate with possible faults on Hydro One LV systems.

- The Transfer Trip and the Block signals from IamGold will be cascaded to Porcupine TS through Timmins TS.

- Line P15T (Timmins TS)
  - A and B protections will connect to the new freestanding CT on the bus connection. This will zone the line protections between P13T and P15T, and will ensure that no settings changes will be required for the specific operating conditions that would allow the bus tie to be closed. Cross-tripping shall be enabled when the bus-tie is closed.
  - A delay of 150ms for the Zone 1 at Timmins TS will be required in both Group settings. The settings will otherwise remain the same.

3.3.2 IamGold Facility

- Redundant transformer and HV bus protections are required to be compliant with the Transmission System Code (TSC).
- With the high ratio of line to transformer impedance a blocking signal will be required to be sent for faults at the proponent's facility.
- The proponent shall place a distance based protection as zoned by the connecting breaker's CTs looking into the facility with the settings below.
  - Upon detection of fault IamGold will send a block signal over both the main and alternate channel to Timmins TS and trip its own facilities.
  - The reverse looking zone element shall have coverage further than the group 2 zone 2 element at Porcupine TS. It shall be set at 125% of the difference between the group 2 zone 2 setting and the positive sequence line impedance.
- The 115kV circuit breakers are required to be equipped with breaker failure protection. When the HV circuit breaker connected to T2R fails, transfer trip signals (TT) must be sent to HONI through dual channels. The transfer tripping must be interlocked by the status of the local disconnect switch. Once the disconnect switch is opened, the transfer trip signals shall be removed.
- The proponent is responsible to establish dual telecommunication channels (Main and Alternate) to Timmins TS for the protection settings in Operating Condition 1 of line T2R.
- In operating condition 2 (group 2 settings for P13T) the block and transfer trip shall be cascaded through Timmins TS to Porcupine TS.
- IamGold will be required to participate in a Load Rejection SPS.
  - Should either T3 or T4 at Porcupine TS be out of service the proponent will be tripped.

4 FAULT CLEARING TIMES

- T2R
  - The longest fault clearing time for T2R will be for a line end fault.
  - MR (measuring relay) + DT (delay time) + BTM (breaker trip module) + BKR (breaker open time) = 25ms + 50ms + 6ms + 83ms = 164ms
- P13T (Group 1/Operating Condition 1)
  - The group 1 longest fault clearing time will be for a line end fault with the opposite line end open: MR (measuring relay) + DT (delay time) + BTM (breaker trip module) + BKR (breaker open time) = 25ms + 50ms + 6ms + 83ms = 164ms. This is an increase from the 144ms permissive echo longest fault clearing time.
- P13T (Group 2/Operating Condition 2)
  - For a fault on T2R Porcupine will detect the fault after the delay time and transfer trip Timmins TS.
    - MR (measuring relay) + DT (delay time) + TP (teleprotection) + BTM (breaker trip module) + BKR (breaker open time) = 25ms + 80ms + 15ms + 6ms + 83ms = 209ms
  - Upon loss of teleprotection the maximum fault clearing time becomes the local trip time at Porcupine plus the local trip time at Timmins:
    - MR (measuring relay) + DT (delay time) + BTM (breaker trip module) + BKR (breaker open time) + MR (measuring relay) + DT (delay time) + BTM (breaker trip module) + BKR (breaker open time) = 2 x (25ms + 50ms + 6ms + 83ms) +30ms (additional delay needed by Porcupine) = 358ms.

The Protection Impact Assessment that deals exclusively with protection and tele-protection. However, should this become a project, all other protection, control and telecom items will be addressed according to IESO Market Rules in the Transmission Planning Specification.