Hydro One Networks Inc.

483 Bay Street, South Tower, 8th Floor
Toronto, Ontario, Canada
M5G 2P5

LAW
Michael Engelberg, Assistant General Counsel
Telephone: (416) 345-6305
Fax: (416) 345-6972
E-mail: mengelberg@HydroOne.com

July 26, 2018

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

BY RESS AND COURIER

Dear Ms Walli:

Re: EB-2018-0218 – Hydro One Sault Ste. Marie's Application and Evidence for 2019 Rates and Other Related Matters

Enclosed are two paper copies of Hydro One Sault Ste. Marie's ("HOSSM") Application and evidence for the above-noted matter. The documents are also being submitted by using the Ontario Energy Board's ("OEB") Regulatory Electronic Submission System. The Application includes HOSSM's rate information to support the issuance of notice by the OEB.

HOSSM will post electronic copies of the Application and supporting evidence on its website for public access. A text-searchable Adobe Acrobat electronic version will also be sent to the OEB. In addition, HOSSM will make a copy of the Application and supporting evidence available for public access at the HOSSM office located at 2 Sackville Road, Suite B, Sault Ste. Marie, Ontario.

HOSSM's points of contact for service of documents associated with the Application are listed in Exhibit A, Tab 2 Schedule 1.

Yours very truly,

ORIGINAL SIGNED BY MICHAEL ENGELBERG

Michael Engelberg

encs

1 # EXHIBIT LIST

Ex	Tab	Sch	Att	Contents
A				**ADMINISTRATION**
A	1	1		Exhibit List
A	2	1		Application and Administration
A	2	1	1	Certification of the Evidence
A	2	2		Compliance with Past OEB Decisions
A	2	3		Compliance with OEB Filing Requirements
A	3	1		Managers Summary of Application
A	3	1	1	Requested Approvals – Chapter 2, Appendix 2-A
B1				**TRANSMISSION SYSTEM PLAN**
B1	1	1		Transmission System Plan
B1	1	2		Letter from METSCO Energy Solutions
B2				**Supporting Schedules**
B2	1	1		Capital Projects and Expenditures
B2	1	1	1	Capital Projects Table - Chapter 2, Appendix 2-AA
B2	1	1	2	Capital Expenditures - Chapter 2, Appendix 2-AB
B2	2	1		Capital Plan Evolution
B2	3	1		Customer Engagement
B2	3	1	1	2018 PUC Customer Engagement Meeting Minutes
B2	3	1	2	2018 API Customer Engagement Meeting Minutes
B2	3	1	3	2018 Essar Algoma Customer Engagement Meeting Minutes
B2	3	1	4	2018 Brookfield Customer Engagement Meeting Minutes
B2	3	2		Customer Engagement Worksheet – Chapter 2 Appendix 2-AC
C				**SERVICE QUALITY, RELIABILITY PERFORMANCE AND REPORTING**
C	1	1		Performance Management and Continuous Improvement
C	2	1		Reliability Performance
C	2	1	1	Customer Delivery Point Performance Standards
C	3	1		Benchmarking
D				**COST ALLOCATION AND RATE DESIGN**
D	1	1		Revenue Cap IR Mechanism and Components
D	1	1	1	Transmission Study for Hydro One Electric: Recommended CIR Parameters and Productivity Comparisons
D	2	1		Uniform Transmission Rates and Charge Determinants

APPLICATION AND ADMINISTRATION

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15 (Sched. B)

AND IN THE MATTER OF an application by Hydro One Sault Ste. Marie Inc. on behalf of Hydro One Sault Ste. Marie Limited Partnership for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2019 transmission rates and related matters.

EB-2018-0218

1. The applicant, Hydro One Sault Ste. Marie Inc. ("HOSSM"), carries on the business of owning and operating electricity transmission facilities in the vicinity of Sault Ste. Marie, Ontario.

2. HOSSM's core business is the operation of a regulated transmission utility in Ontario. However, from time to time HOSSM may encounter matters that may be considered to be non-utility business. To the extent these matters arise, the impacts are segregated from HOSSM's rate-regulated activities.

3. In accordance with Chapter 2 of the *Filing Requirements for Electricity Transmission Applications*, dated July 20, 2017, the default materiality threshold is 0.5% of the revenue requirement for transmitters with a revenue requirement greater than $10 million and less than or equal to $200 million. HOSSM's

revenue requirement falls within this range, and therefore HOSSM's materiality threshold for this application is approximately $200,000 (calculated as $201,277 for 2019, which is $40,255,457* 0.5%).

4. HOSSM hereby applies to the Ontario Energy Board (the "Board" or the "OEB") for an Order or Orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998,* as amended (the "OEB Act"), approving HOSSM's proposed revenue to be reflected Ontario's 2019 transmission electricity rates.

5. The Applicant has followed the filing requirements applicable to a revenue cap index proposal, as set out OEB's *Filing Requirements for Electricity Transmitters* and discussed in Exhibit A, Tab 2, Schedule 3.

6. In the OEB's Decision and Order for Hydro One Inc.'s Mergers, Acquisitions, Amalgamations and Divestitures ("MAAD"s) application EB-2016-0050, the OEB approved a ten-year deferral period for rebasing of the revenue requirement of Great Lakes Power Transmission Inc. ("GLPT"). (On January 16, 2017, GLPT's name was changed to Hydro One Sault Ste. Marie LP.) In the same Decision and Order, the OEB determined that HOSSM would continue with the 2016 revenue requirement and bring forward a separate rate application, proposing a revenue cap index for the deferral period.

7. HOSSM hereby applies to the OEB for approval of the proposed revenue cap index framework methodology put forth in the application to determine revenue requirement for the years 2019 to 2026 inclusive.

8. HOSSM is seeking OEB approval for 2019 base revenue requirement of $40,255,457 which was calculated using HOSSM's 2016 OEB approved revenue requirement as the base revenue adjusted by an annual adjustment under the revenue cap index framework to be included in the Board's determination of the 2019 Uniform Transmission Rates for Ontario.

9. HOSSM requests that the proposed revenue requirement be reflected in rates effective January 1, 2019. However, if implementation occurs after January 1, 2019, HOSSM requests that the existing transmission rates be made interim to permit the implementation of the proposed revenue requirement effective as of January 1, 2019.

10. HOSSM also requests an accounting order to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2019 until HOSSM's proposed 2019 rates are implemented, if necessary.

11. Furthermore, HOSSM is requesting approval to disburse, through the use of account 1595, the balances in various deferral and various accounts in 2019 as described more particularly in Exhibit E, Tab 1, Schedule 1 of the pre-filed evidence.

12. Based upon the Board's Decision in EB-2009-0409, HOSSM will continue to maintain in the test period sub-accounts for Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs, within account 1508; and based upon the Accounting Procedures Handbook, HOSSM will continue to maintain in the test period account 1592 for tax variances and account 1595 related to previously approved regulatory asset collections.

13. HOSSM will seek to establish a new Z-factor deferral Account 1572 to recover the material costs, associated with any unforeseen event that is outside the control of HOSSM, and which meets the defined causation, materiality and prudence criteria in accordance with the OEB's Chapter 2, Filing Requirements for Electricity Transmission Applications dated February 11, 2016.

14. As outlined in the OEB Handbook to Electricity Distributor and Transmitter Consolidations, dated January 19, 2016, HOSSM will apply for an Incremental Capital Module ("ICM") funding in the event HOSSM encounters unplanned capital expenditures prior to any rebasing application to be filed for 2026 rates.

15. As approved by the Board in EB-2016-0050, HOSSM will implement an Earnings Sharing Mechanism ("ESM") that will take effect during the last five years of the rebasing deferral period (2022 to 2026 inclusive).

16. This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

17. The Applicant requests that, pursuant to Section 34.01 of the Board's *Rules of Practice and Procedure*, this proceeding be conducted by way of written hearing.

18. HOSSM's internet address is https://www.glp.ca. More specifically, this application and related documentation can be found on the HOSSM website at https://www.glp.ca .

19. HOSSM's neighbouring utilities are PUC Distribution Inc. (ED-2002-0546), Hydro One Networks Inc. (ED-2003-0043, ET-2003-0035); and Algoma Power

Inc. (ED-2009-0072). All persons in Ontario are affected by this Application as this application impacts Ontario's Uniform Transmission Rates. It is therefore impractical to set out their names and addresses because they are too numerous.

20. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Ms. Linda Gibbons
Senior Regulatory Coordinator – Regulatory Affairs
Hydro One Networks Inc.

Mailing Address:	7th Floor, South Tower 483 Bay Street Toronto, Ontario M5G 2P5
Telephone:	(416) 345-4373
Fax:	(416) 345-5866
Email:	regulatory@HydroOne.com

The Applicant's Counsel:

Michael Engelberg
Hydro One Networks Inc.
Law Division
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5

Telephone:	(416) 345-6305
Fax:	(416) 345-6972
Email:	mengelberg@HydroOne.com

DATED at Toronto, Ontario, this 26th day of July, 2018.

By its counsel,

Michael Engelberg

Michael Engelberg

CERTIFICATE OF EVIDENCE

TO: ONTARIO ENERGY BOARD

The undersigned, being Hydro One Sault Ste. Marie LP, General Manager, Kevin Lewis, hereby certifies for and on behalf of Hydro One Sault Ste. Marie LP that:

1. I am a senior officer of Hydro One Sault Ste. Marie LP;

2. This certificate is given pursuant to the Ontario Energy Board's *Filing Requirements for Electricity Transmission Rate Applications* (last revised on February 11, 2016)*;* and

3. The evidence submitted in support of Hydro One Sault Ste. Marie's 2019 Transmission Revenue Cap Incentive Rate-setting application (EB-2018-0218) filed with the OEB is accurate, consistent and complete to the best of my knowledge.

DATED this 26th day of July, 2018.

KEVIN M. LEWIS

COMPLIANCE WITH PAST OEB DECISIONS

1. INTRODUCTION

The following outlines the requirements and directions issued to Hydro One Sault Ste. Marie LP ("HOSSM"), including those issued to Great Lakes Power Transmission Limited Partnership ("GLPT"), by the Ontario Energy Board ("OEB" or the "Board") in Decisions and Orders from previous proceedings and where to locate the pertinent evidence in this application.

1.1 EB-2014-0238

Great Lakes Power Transmission Inc. on behalf of GLPT filed a complete cost of service application with the OEB on July 14, 2014 under section 78 of the OEB Act, 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its electricity transmission revenue requirements for 2015 and 2016 to be effective January 1, 2015 and January 1, 2016.

As directed, a Settlement Conference was convened on October 28, 2014 in accordance with the OEB Rules of Practice and Procedure (the "Rules") and the OEB's Practice Direction on Settlement Conferences (the "Practice Direction"). On November 12, 2014, GLPT informed the Board that the Parties had reached a comprehensive agreement on all issues.

Listed below are the settlement issues that GLPT agreed to, with HOSSM's response to in this application.

- undertake a more detailed and comprehensive asset management plan as part of GLPT's next rate application;

   - This direction was not satisfied in the subsequent HOSSM rate application (EB-2016-0356) and was noted as one of the reasons that rate application was denied. In this application, HOSSM has submitted a Transmission System Plan ("TSP") that describes the asset management plan in detail. See Exhibit B1, Tab 1, Schedule 1.
- participate in Hydro One Networks's Total Cost Benchmarking Study (described in the proposed Settlement Proposal filed in EB-2014-0140) through the provision of relevant data, if GLPT requested to do so;
   - As stated in the application evidence in proceeding EB-2016-0356, Exhibit 1, Tab 2, Schedule 15, section 2.2, GLPT participated in the stakeholder consultation process related to HONI's study, and was prepared to provide the relevant data. However, GLPT was not selected as a comparator and since no request was received to provide data, GLPT did not participate further in the Study.
- complete a new lead lag study as part of GLPT's next rate application
   - As stated in the application evidence in proceeding EB-2016-0356, Exhibit 1, Tab 2, Schedule 15, section 2.3, GLPT undertook to complete a new lead lag study as part of its next rate application. However, as described in the Board's Decision and Order in MAADs proceeding EB-2016-0050, the OEB approved a ten year deferral period for rebasing of rates. Consequently, the application was not a cost-of-service application and thus did not contain a component related to working capital, and therefore GLPT did not file an updated lead lag study. No new lead lag study has been filed as part of this application.
- prepare a new, bottom-up load forecast for submission to the Board with GLPT's next rate application.
   - As stated in the application evidence in proceeding EB-2016-0356, Exhibit 1, Tab 2, Schedule 15, section 2.4, GLPT engaged an independent

consultant to prepare a new, bottom-up (Customer) load forecast for submission in its next rate application. The load forecast was completed in 2016. However, as the Board's Decision and Order in EB-2016-0050 approved a ten year deferral period for rebasing of rates this forecast was not included in the evidence for that application. For the same reason, the new forecast study is not included in this application.

1.2 EB-2016-0050

On October 13, 2016, the OEB approved an application by Hydro One Inc. to purchase all of the issued and outstanding voting securities of GLPT's general partner, Great Lakes Power Transmission Inc. ("the MAADs decision").

The OEB accepted Hydro One's proposal to defer the rebasing of rates for GLPT for a 10 year period as well as the implementation of the proposed earning sharing mechanism for years six to ten of the rebasing of rates deferral period. The OEB did not accept the proposal to reset the rates for GLPT at the beginning of the ten year period and determined that GLPT was to continue with its existing 2016 revenue requirement. The OEB directed GLPT to file a new rate application, proposing a revenue cap index framework for the deferral period that also includes the components set out in the updated Chapter 2 Filing Requirements for Electricity Transmission Applications (Transmission Filing Requirements). This application is a result of that direction.

1.3 EB-2016-0356

GLPT, now HOSSM, filed an application with the OEB on December 23, 2016, seeking approval for changes to its electricity transmission revenue requirement, to be effective January 1, 2017. In the OEB's Decision and Order dated September 28, 2017, the OEB denied the application stating it found the application to be deficient as it did not meet the guidance provided in the MAAD decision[1] and the OEB's 2016 Filing Requirements for Electricity Transmission Applications ("Transmission Filing Requirements"). HOSSM's approved 2016 revenue requirement and charge determinants remained in effect in 2017. Specific OEB findings in EB-2016-0356 are described below with HOSSM's response.

Revenue Cap Index Framework

The Decision noted that the Transmission Filing Requirements include the expectation for the development of a revenue cap index framework, as well as productivity and stretch commitments, and invited transmitters to propose and substantiate the appropriate method and commitments for these elements. The OEB found that "a revenue cap index that is simplified to just the inflation factor should not be the default option if the utility does not provide transmitter-specific metrics. There is insufficient evidence for the OEB to accept HOSSM's submission that the productivity and stretch factors should be 0%, as zero has a value and meaning in an incentive-based framework".[2] Comments regarding the individual components of the index framework provided by the OEB in the Decision and Order in proceeding EB-2016-0356 are found below. Evidence to support HOSSM's proposed revenue cap index framework is found in Exhibit D, Tab 1, Schedule 1.

Inflation Factor

The inflation factor for distributors is based on a two-factor input price index that uses component weights of 30% for labour and 70% for non-labour. The OEB stated that

---

[1] The MAAD decision (EB-2016-0050) indicated that a separate rate application with a revenue cap index could be brought forward. As guidance, the decision stated that the application would be expected to incorporate the components of the incentive-based revenue cap index set out in the Transmission Filing Requirements.
[2] EB-2016-0356 Decision and Order – Page 4

evidence regarding the appropriate input weights should be included in any subsequent rate application by HOSSM.

- In this application, HOSSM has proposed component weights for transmitters of 86% of the annual percentage change in Canada's Gross Domestic Product-Implicit Price Index, Final Domestic Demand ("GDP-IPI FDD") for Canada as reported by Statistics Canada; and 14% of the annual percentage change in the Average Weekly Earnings ("AWE") for workers in Ontario, as reported by Statistics Canada are described in Exhibit D, Tab 1, Schedule 1, Attachment 1.

<u>Productivity Factor</u>

The historical record shows that the OEB set the 0% productivity factor for distributors in its Rate Setting and Benchmarking Report based on a Total Factor Productivity ("TFP") analysis that considered the impact of IFRS, smart meters and Conservation and Demand Management program costs on distributor input data collected over 10 years[3]. OEB staff, AMPCO, and SEC agreed that a TFP study should be completed by Hydro One Transmission for its 2019 Revenue Requirement Application. The OEB could not find that the 0% productivity factor for distributors should be applicable to HOSSM in 2017 without better evidence of its applicability to transmitters.

- As indicated in EB-2016-0356, HOSSM intends to adopt the productivity factors that will be proposed by Hydro One Transmission in its 2019-2022 revenue requirement application. The appropriateness of the Productivity Factor is supported by a TFP study found as Exhibit D, Tab 1, Schedule 1, Attachment 1.

[3] EB-2016-0356, Decision and Order – Page 6

Stretch Factor

In the OEB Decision, HOSSM suggests that it was not cost effective or timely to acquire such evidence for a stretch factor prior to operational integration with Hydro One Transmission. Operational integration with Hydro One Transmission is expected to occur on October 1, 2018.

- The new TFP study completed to support Hydro One Transmission's rate application is found as Exhibit D, Tab 1, Schedule 1, Attachment 1. Support for the appropriateness of the Stretch Factor is found in this study.

Scorecard

The OEB found that the proposed scorecard for 2017 was incomplete. While there has been some progress in identifying potential enhancements to performance outcomes, HOSSM falls short of the OEB expectations for performance metrics, each with specific outcomes and implementation timelines. And while a scorecard submitted after 2019 may reflect future operational changes, the current application must comply with the scorecard requirements in 2017, the year in which rate increase is proposed.[4]

- HOSSM advised that it will provide the results of its proposed scorecard for 2016 and for completed quarters in 2017 in its 2018 application. Evidence in this application regarding the proposed HOSSM scorecard is found in Exhibit C, Tab 1, Schedule 1.

Asset Management Plan

The OEB noted that HOSSM has outstanding commitments from the OEB-approved settlement proposal including studies, plans and measures that were to be filed as part of its next rates application. The OEB appreciated that those commitments were made prior

[4] IBID – Page 9

to purchase of its shares by Hydro One, yet a revenue cap index application is a rates application within the meaning of the settlement proposal. It is the OEB's expectation that when it approves a settlement proposal, the parties will fulfill the commitments contained therein[5].

- The Asset Management Plan promised as a part of the Settlement Agreement is found in this application in Exhibit B1, Tab 1, Schedule 1.

Deferral and Variance Accounts ("DVA")

The OEB did not approve the disposition of the balance of $975,219 recorded in the DVAs as at December 31, 2016 as the application to adjust the revenue requirement was denied. The OEB also directed that all other DVA accounts will remain open and continue to accrue interest, as applicable, pending future review and approval by the OEB.

- Updated evidence regarding the proposed disposition of the Regulatory Accounts is included in Exhibit E, Tab 1, Schedule 1.

[5] IBID – Page 10

COMPLIANCE WITH OEB FILING REQUIREMENTS FOR ELECTRICITY TRANSMITTERS

Hydro One Sault Ste. Marie ("HOSSM") filed an application with the Ontario Energy Board (OEB) on December 23, 2016, seeking approval for changes to its electricity transmission revenue requirement, to be effective January 1, 2017[1]. In the OEB's Decision and Order dated September 28, 2017, the OEB denied the application stating it found the application to be deficient as it did not meet the guidance provided in the MAADs decision or the OEB's 2016 Filing Requirements for Electricity Transmission Applications (Transmission Filing Requirements). The Decision and Order for the MAADs proceeding[2] states:

> *"The OEB does not fully accept the rate-setting framework for GLPT rates, as proposed by Hydro One for the reasons set out in the Decision. The OEB is prepared to accept Hydro One's proposal to defer the rebasing of rates for GLPT for a 10 year period as well as the proposed earning sharing mechanism, but cannot simultaneously accept the proposal that rates for GLPT must be reset at the beginning of this ten year period. The OEB has determined that GLPT can continue with its existing revenue requirement and file a new rate application, proposing a revenue cap index framework for the deferral period. It should include the components set out in the updated Chapter 2 Filing Requirements for Electricity Transmission Applications (Transmission Filing Requirements)."*

This application was developed in accordance with this direction and guidance provided by the OEB. For further discussion, refer to Exhibit A, Tab 2, Schedule 2.

---

[1] EB-2016-0356
[2] EB-2016-0050

HOSSM has followed the filing requirements applicable to a revenue cap index proposal, as set out in:

- Chapter 2 of the Board's Filing Requirements for Electricity Transmission Applications, Chapter 2: Revenue Requirement Applications dated February 11, 2016;
- Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5: Consolidated Distribution System Plan Filing Requirements dated March 28, 2013;
- The Board's Handbook to Electricity Distributor and Transmitter Consolidations dated January 19, 2016 ("the Handbook");
- The Board's direction as set out in the Decision and Order in proceeding EB-2016-0050: Application for the acquisition of Great Lakes Power Transmission Inc. by Hydro One dated October 13, 2016; and
- The Board's direction as set out in the Decision and Order in proceeding EB-2016-0356: HOSSM application for electricity transmission revenue requirement effective January 1, 2017 dated September 28, 2017.

MANAGERS SUMMARY OF APPLICATION

1. INTRODUCTION

On March 10, 2016 Hydro One Inc. ("HOI") filed a Section 86 (2) (b) Application for the Leave to Purchase Voting Securities of Great Lakes Power Transmission Inc. ("HOSSM") with the Ontario Energy Board ("OEB") (EB-2016-0050). In that application, HOI sought OEB acceptance of a proposed 10 year rate rebasing deferral period, an earnings sharing mechanism, and a methodology to calculate HOSSM's revenue requirement during the deferral period. Along with approving the purchase of the securities, the OEB accepted HOI's proposal to defer the rebasing of rates for HOSSM for a 10 year period as well as its proposed earnings sharing mechanism, but did not accept the proposed rate-setting framework for HOSSM, namely, the resetting of rates at the beginning of a 10-year deferral period:

> *"…rate-setting policies associated with consolidation are predicated on the notion that the going-in rates are the rates intended to provide the revenues required as the starting point to achieve savings over the deferred rebasing period[1]".*

In its Decision[2], the OEB granted leave to purchase all of the issued and outstanding voting securities of Great Lakes Power Transmission Inc. and determined that HOSSM was to continue with its existing 2016 revenue requirement that was approved in

[1] EB-2016-0050 Decision and Order, page 17
[2] EB-2016-0356 Decision and Order, dated September 28, 2016, to determine the 2017 HOSSM revenue requirement application

proceeding EB-2014-0238 and file a new rate application, proposing a revenue cap index framework for the rebasing deferral period.

As a result, a transmission rate application (EB-2016-0356) was filed by Great Lakes Power Transmission Inc. based on a revenue cap index for 2017 modeled on the price cap incentive regulation framework ("Price Cap IR') used for distributors. This application provided a revenue price cap index calculated in the same fashion as a Price Cap IR for distributors, with an inflation factor of 1.90%, less productivity and stretch factors of zero percent, and the disbursal of certain deferral and variance accounts.

This application was denied as the OEB found the application was deficient as it did not meet the guidance provided in the MAADs decision[3] and the OEB's 2016 *Filing Requirements for Electricity Transmission Applications* ("Transmission Filing Requirements"). Hydro One SSM's approved 2016 revenue requirement[4] and charge determinants remained in effect for 2017.

Specifically, the OEB found that an essential component of an incentive-based revenue cap index was missing - the sharing of benefits with customers achieved through productivity and stretch factors that reduce the inflationary increase sought. The OEB deemed that there was insufficient evidence to accept HOSSM's submission that the productivity and stretch factors should be 0%, as zero has a value and meaning in an incentive-based framework. The OEB also stated that the scorecard fell short of the OEB's expectations and a comprehensive asset management plan in the form of a

[3] MAADs application proceeding EB-2016-0050

[4] Approved in OEB Decision and Order in proceeding EB-2014-0238, dated December 16, 2014 for GLPT 2015 and 2016 rates.

Transmission System Plan ("TSP") that was committed to by HOSSM prior to purchase by Hydro One was still required.

This application is submitted following the direction given by the OEB and contains the evidence specifically identified, including:

- a proposed revenue cap index framework supported by a third party Total Factor Productivity Study for transmission;
- a newly evolved scorecard with proposed targets; and
- a TSP that describes HOSSM's assessment management plan including but not limited to capital projects and programs, asset health indexes and an asset condition assessment.

Effective Date of Rates

HOSSM requests that the proposed revenue requirement be reflected in rates effective January 1, 2019. For 2019, if implementation of approved rates occurs after January 1, 2019, HOSSM requests that an accounting order be approved to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2019 until HOSSM's proposed 2019 revenue requirement and rates are implemented.

In the summary that follows, HOSSM has provided a general overview of the Application and identifies key aspects of the Application for the Board to consider.

2. GENERAL OVERVIEW

2.1 TRANSMISSION SYSTEM PLAN

Exhibit B1, Tab 1, Schedule 1 contains HOSSM's first TSP. As the integration process between Hydro One and HOSSM progresses, HOSSM will continue to migrate its practices and processes to align with Hydro One's. The TSP provides a description of HOSSM, its assets and asset lifecycle optimization. It also describes the current status of HOSSM's asset management and investment plan processes, expected efficiencies, and material projects and programs planned for the rebasing deferral period (2018 to 2026).

To better understand the asset and system requirements, asset health condition and risk and value to customers, and to ensure HOSSM's investment plan was developed using sufficient rigour, Hydro One hired METSCO Energy Solutions to perform an in-depth Asset Condition Assessment ("ACA") on HOSSM's assets. Data was gathered from numerous sources including two different electronic systems (Sunguard and Elkie), paper copies of inspection reports and test results, inspections, interviews and team meetings that included staff from Hydro One, HOSSM, and METSCO. Data from test result reports from third parties such as One Line Engineering, Kinectrics, S.D. Myers, and Linewise, were also used to complete the ACA. The ACA is found as Appendix B of the TSP.

As the integration process continues, it is expected that during the rebasing deferral period efficiencies will be identified as HOSSM's standards, processes and practices are aligned with Hydro One's. During the investment plan annual review process, investments and pacing may be adjusted as required using the investment prioritization process.

2.2 PERFORMANCE AND REPORTING

HOSSM has aligned the new evolved scorecard with the principles of the OEB's Renewed Regulatory Framework ("RRF") and Hydro One's proposed scorecard that will be submitted in the Hydro One Networks Transmission Rate Application. As HOSSM is integrated with Hydro One, HOSSM will become part of the Hydro One metrics. In the meantime, HOSSM will begin collecting data in a manner to allow it to align with the metrics used and reported on by Hydro One. HOSSM has historically developed annual Key Performance Indicators ("KPIs") for business performance measurement and is committed to continuous improvement in performance to maximize value for the ratepayer. The evolution of a balanced scorecard as described in Exhibit C, Tab 1, Schedule 1 will further enhance HOSSM's performance management and ensure that the objectives and goals of the company are being managed to create additional value for the ratepayer.

Reliability is an important metric included in HOSSM's proposed scorecard. HOSSM uses Customer Delivery Point Performance Standards ("CDPPS") and unsupplied energy data to monitor its service quality and reliability. HOSSM's CDPPS statistics indicate that reliability is either improving or being maintained at levels that are equal or superior to the standard average of performance. In addition, HOSSM's unsupplied energy performance is meeting or exceeding the threshold set by the IESO.

HOSSM's reliability metrics and proposed scorecard are further discussed in Exhibit C, Tab 2, Schedule 1.

2.3 REVENUE CAP ANNUAL ADJUSTMENT

In accordance with the Decision and Order in EB-2016-0050, HOSSM has calculated its proposed 2019 revenue requirement, by using an annual adjustment to its 2016 OEB approved revenue requirement. As suggested by OEB staff, AMPCO and SEC and noted in the EB-2016-0356 Decision, the annual adjustment is based on the proposed inflation, productivity and stretch factors resulting from a Total Factor Productivity study. The study was commissioned by Hydro One Networks and performed by Power System Engineering Inc. The revenue cap index framework components and calculation methodology are discussed in Exhibit D, Tab 1, Schedule 1, and the study is Attachment #1 to that exhibit.

2.4 DEFERRAL AND VARIANCE ACCOUNTS

HOSSM is requesting approval for continuance of the following deferral/variance accounts:

- Other Regulatory Assets Account 1508 sub-accounts Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs, Property Tax and Use and Occupation Permit Fee, IFRS Gains and Losses and OEB Cost Assessment;
- Based upon the Board's Decision in EB-2009-0409, HOSSM will continue to maintain in the test period the sub-account for Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs, within account 1508;
- Based upon the Accounting Procedures Handbook, HOSSM will continue to maintain in the test period account 1595 related to previously approved regulatory asset recovery;
- As described in the OEB's 2008 report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, OEB policy prescribes a 50/50 sharing of impacts of legislated tax changes from a utility's

tax rates embedded in its OEB approved base rate known at the time of application. HOSSM is proposing to maintain in the rebasing deferral period, a sub-account within account 1592 to capture these impacts; and

- An accounting order to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2019 until HOSSM's proposed 2019 rates are implemented, if necessary.

As described in more detail in Exhibit E, Tab 1, Schedule 1, in the event HOSSM encounters unforeseen events which meet the three defined eligibility criteria of Causation, Materiality and Prudence, a new Z-factor deferral account would be requested at that time, to be established in Account 1572.

Furthermore, HOSSM is requesting approval to disburse the balances in the following accounts:

- Four sub-accounts of account 1508:
    - Comstock Claim;
    - Property Tax and Use and Occupation Permit Fee Variance;
    - Bulk Energy System ("BES") definitional change; and
    - OEB Cost Assessment Variance; and
- Account 1595 related to previously approved regulatory asset collections.

Subject to the approval of the various account balances that HOSSM is seeking to disburse as part of this Application, it is HOSSM's position that the most administratively efficient method to disburse the various account balances would be to aggregate the balance of all accounts, including the remaining balance in account 1595, and disburse the balance in 2019. HOSSM is seeking to disburse the aggregate credit balance of $94,909 by decreasing its 2019 revenue requirement to be used in the calculation of the

UTR. This disbursal methodology is consistent with prior rate applications, and is described in more detail in Exhibit E, Tab 1, Schedule 3.

2.5 RATE DESIGN AND RATES

Aspects related to rate design, including the calculation of the UTR, are set out in Exhibit D, Tab 2, Schedule 1. In calculating the 2019 UTR, HOSSM has used the base revenue requirement sought in this Application of $40,255,457, plus the forecasted disbursal related to the net deferral and variance accounts of a credit of $94,909 for a total of $40,160,548

The proposed 2019 UTRs arising from this Application are expected to remain unchanged from 2018, as follows:

- Network Rate: $3.61 per kW
- Line Connection Rate: $0.94 per kW
- Transformation Connection Rate: $2.34 per kW

2.6 BILL IMPACTS

The change in the HOSSM revenue requirement does not result in any change to the existing UTRs. HOSSM estimates that the revenue requirement increases arising in this application will result in a negligible impact to the typical residential and retail customer's total bill for 2019. For further information on bill impacts, refer to Exhibit D, Tab 2, Schedule 2.

Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

is seeking the following approvals in this application:

1		Hydro One Sault Ste. Marie ("HOSSM") hereby applies to the Ontario Energy Board (“OEB”) for approval of the proposed revenue cap index framework methodology put forth in the application to determine rates for the years 2019 to 2026 inclusive.
2		HOSSM hereby applies to the OEB for approval for 2019 base revenue requirement of $40,255,457 which was calculated using GLPT’s 2016 OEB approved revenue requirement as the base revenue adjusted by an annual adjustment under the revenue cap index framework to be included in the Board’s determination of the 2019 Uniform Transmission Rates for Ontario.
3		HOSSM requests that the proposed revenue requirement be reflected in rates effective January 1, 2019. However, if implementation occurs after January 1, 2019, HOSSM requests that the existing transmission rates be made interim to permit the implementation of the proposed revenue requirement effective as of January 1, 2019.
4		HOSSM also requests an accounting order to establish a sub-account within deferral account 1574 to record revenue deficiencies incurred from January 1, 2019 until HOSSM’s proposed 2019 rates are implemented, if necessary.
5		Further HOSSM is also requesting approval to disburse, through the use of account 1595, the balances in various deferral and various accounts in 2019 as described more particularly in Exhibit E, Tab 1, Schedules 1 to 4 of the pre-filed evidence.
6		

Hydro One Sault Ste. Marie

2018-2026 Transmission System Plan

1.0 INTRODUCTION AND SUMMARY

Hydro One Sault Ste. Marie Limited Partnership ("HOSSM") prepared this 2018-2026 Transmission System Plan ("TSP" or "Plan") in accordance with Chapters 2, 3 and 5 of the Ontario Energy Board's ("OEB") *Filing Requirements for Electricity Transmission Applications* published on February 11, 2016. HOSSM has elected to submit a standalone TSP rather than integrating it with the 2018-2022 Hydro One Networks ("Hydro One") TSP, as was also contemplated at the time of the 2017 proceeding[1]. A standalone TSP best reflects HOSSM's objectives of articulating to the OEB and other stakeholders the scope, nature, and progress to date of the integration activities between HOSSM's asset management and system planning functions and those of Hydro One Networks.

HOSSM submits that this TSP is distinct from most Transmission and Distribution System Plans submitted to the OEB in that it is not being filed to support any additional capital funding requests. As previously articulated by Hydro One in the application for acquisition of Great Lakes Power Transmission Limited Partnership ("GLPT"), HOSSM's rebasing is being deferred for a 10-year period.[2] Accordingly, the planning tools, processes, and investments outlined in this Plan represent a work program that HOSSM expects to execute within the envelope of the currently approved revenue requirement, adjusted by the Revenue Cap Index, and subject to certain unforeseen circumstances.

Since it is not designed to support requests for additional capital funding, this Plan focuses to a greater extent on the dynamics underlying the operational integration of HOSSM's system

---

[1] Ontario Energy Board, EB-2016-0356, *Decision and Order, Hydro One Sault Ste. Marie LP Application for Electricity Transmission Revenue Requirement effective January 1, 2017*. September 28, 2017, page 10

[2] Ontario Energy Board, EB-2016-0050, Decision and order, *Application for the acquisition of Great Lakes Power Transmission Inc. by Hydro One Inc*. October 13, 2016, pp. 24, 25.

planning, operation, and capital work execution activities with those of Hydro One. Operational integration is set to formally commence on October 1, 2018.

While significant progress has been made to date, more work lies ahead, before and after October 1, to facilitate seamless integration of HOSSM's asset management operations with those of Hydro One. As such, the planning activities, along with specific investment projects and programs that this Plan outlines, reflect the integration progress to date. As integration continues over the coming years, additional insights are expected to become available ahead of a future rebasing, at which point HOSSM's transmission planning activities and outputs are expected to be presented as a part of Hydro One's TSP.

1.1 EXECUTIVE SUMMARY

HOSSM has developed this integrated Plan in accordance with the key principles underlying the OEB's Renewed Regulatory Framework ("RRF") principles:

- *Customer Focus*: provision of services in a manner reflective of identified customer needs and preferences;
- *Operational Effectiveness*: leveraging continuous improvement opportunities in productivity and cost performance, while meeting system reliability and service quality objectives;
- *Public Policy Responsiveness*: deliver on the obligations mandated by government in legislation and in regulatory requirements; and
- *Financial Performance*: maintaining financial viability while seeking out and capitalizing on sustainable operational effectiveness improvement opportunities.

The acquisition of all outstanding voting securities of HOSSM's predecessor, Great Lakes Power Transmission Inc. ("GLPT"), by Hydro One, was approved by the OEB on October 13, 2016. Efforts to align the aspects of HOSSM's and Hydro One's asset management and investment planning frameworks have been underway for some time. This TSP reflects the current state of ongoing integration work.

Based on the planning work conducted to date and described in detail throughout this document, HOSSM's integrated Transmission System Plan incorporates the planned investment levels for the period 2018 to 2026 inclusively, as shown in Table 1-1.

Table 1-1: HOSSM 2018-2026 Transmission System Plan

	Plan									**Total**
Category ($M)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Plan**
System Access	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4	$3.4	$0.0	$0.0	**$4.8**
System Renewal	$5.1	$3.0	$8.0	$7.9	$5.9	$7.6	$7.1	$8.7	$7.8	**$61.0**
System Service	$1.3	$1.3	$2.6	$2.8	$5.5	$0.3	$0.3	$1.6	$0.6	**$16.0**
General Plant	$0.1	$2.9	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	**$3.9**
Total	**$6.5**	**$7.1**	**$10.7**	**$10.7**	**$11.5**	**$9.4**	**$10.8**	**$10.4**	**$8.5**	**$85.7**

Key drivers of investments captured in the current iteration of the TSP are the following:

System Renewal:

- Replacement of wooden structures and conductor driven by condition assessments;
- Replacement and modifications of various transmission station equipment based on condition, safety risks and known operating performance issues.

System Service:

- Consolidation of two stations and associated equipment to address operating constraints and safety hazards, while enhancing reliability and operation efficiency.
- Upgrades to functionally obsolete Protection and Control ("P&C") and other equipment at select stations;

System Access:

- A single project to install a spare transformer at HOSSM's Echo River Transformer Station ("TS") identified among the "wires-only" solutions in the course of the last Regional Planning process to enhance area reliability in contingency situations.

General Plant:

- Land acquisition to enable the construction of the new consolidated Greenfield transformer station to replace Goulais and Batchawana transmission stations, along with construction of an indoor storage facility, and funds to enable ongoing upkeep of HOSSM's general plant assets to facilitate work safety and execution efficiency.

As the integration between the Hydro One and HOSSM asset management functions continues over the coming years, HOSSM expects that additional investment drivers may emerge, driven by considerations such as equipment standardization, interoperability, or operational efficiency, among others. As opportunities or requirements for such investments arise, their scope and timing will be determined on the basis of asset risk assessments and investment prioritization processes underlying the current plan. Accordingly, and consistent with the OEB's policy for multi-year capital planning, HOSSM expects the volumes and timing of specific investment types to fluctuate year-to-year within the funding envelope provided by the index-adjusted revenue requirement.

As further discussed in Section 2.3.1 and confirmed by the May 28, 2018 letter from the Independent Electricity System Operator ("IESO") provided in Appendix A, the first cycle of regional planning activities in the East Lake Superior Region that encompasses HOSSM's service territory that took place in 2014, concluded that no further regional coordinated planning was required. Three "wires-only" solutions were identified at that time, one of which is being proposed in the form of the Echo River Spare Transformer project (ISD# SA-01). Accordingly, while the current TSP does not include any investments identified through regional planning activities, it does include a planned investment related to one of the three of these wires-only solutions; with the other two awaiting decisions on the customers' end to facilitate further planning. HOSSM will participate in the second cycle of regional planning activities slated to begin in 2019 and will consider adjustments to future iterations of the plan.

In the instances where application of Hydro One's asset management and investment prioritization approaches or the integration of operating practices provides opportunities to realize efficiencies, HOSSM will use the resulting benefits to manage the annual fluctuations within its capital program that can be expected to occur over the nine-year Plan period. HOSSM will apportion the benefits of any remaining efficiencies in accordance with the framework outlined by the OEB in the decision approving the acquisition of GLPT, which includes an Earnings Sharing Mechanism ("ESM") in effect from 2022.

1.2 DESCRIPTION OF THE UTILITY

HOSSM is a regulated electricity transmitter that owns and operates high-voltage assets in the Algoma District, along the eastern shore of Lake Superior, between the municipality of Wawa and the city of Sault Ste. Marie, Ontario, as depicted on Figure 1-1.

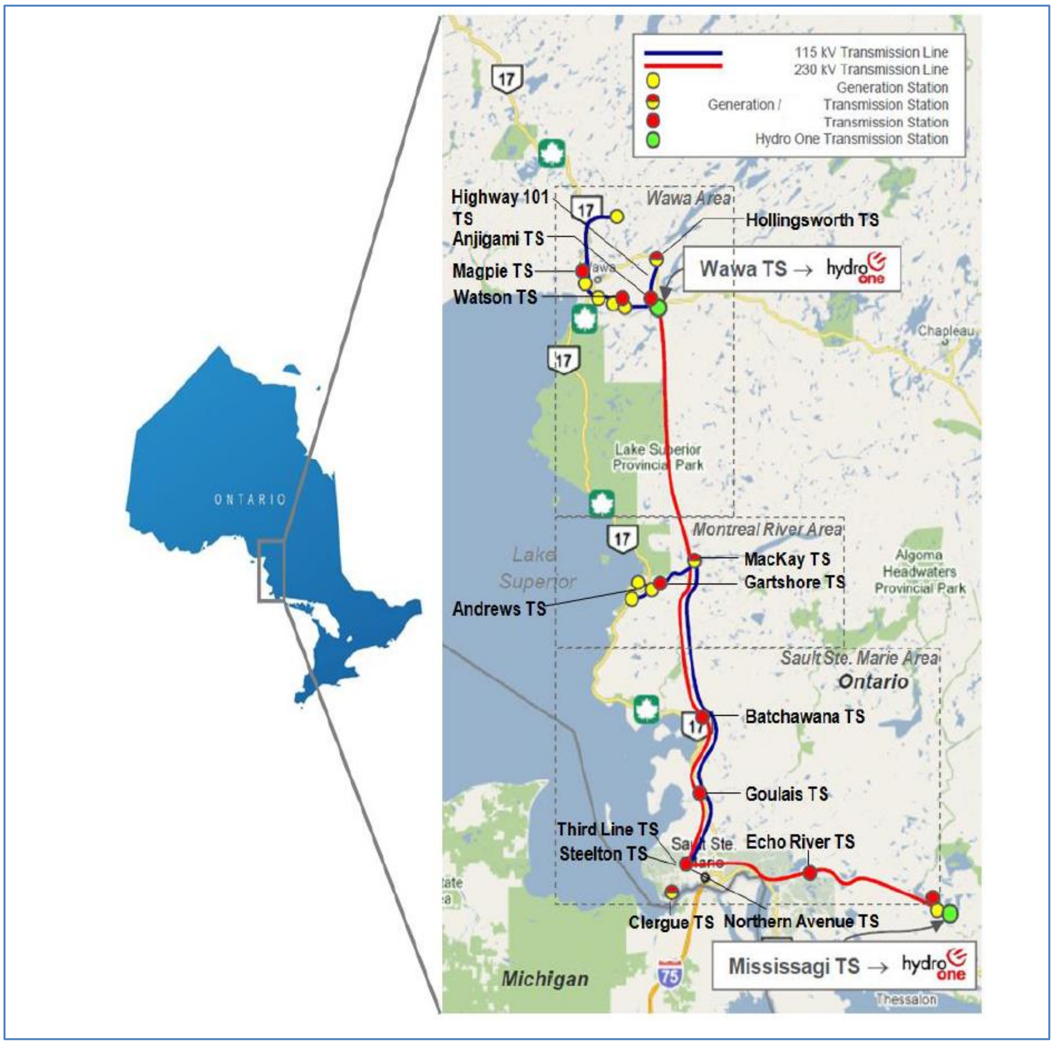


Figure 1-1: HOSSM Service Territory Map

The operating capabilities and location of HOSSM's transmission system provide an important role in the operation of Ontario's bulk transmission system, along with the Hydro One assets that run in parallel, HOSSM's system provides a link connecting the generation capacity and load centres located in Ontario's northwest with the remainder of the IESO-controlled grid. See Section 3.2.1 for additional discussion of system configuration and predominant power flows on the HOSSM system.

HOSSM's transmission infrastructure covers an area of approximately 12,000 square kilometres, supplying power to four industrial customers, two local distribution companies ("LDCs"), and connecting approximately 894 MW of generation capacity. The HOSSM's system peak load is approximately 250 MW in the summer and 300 MW in the winter months, with the majority supplied through the 115 kV circuits from Third Line Transformer Station (TS).

1.2.1 OVERVIEW OF ASSETS MANAGED

HOSSM's asset base primarily consists of line and station equipment, along with a selection of communications, IT, fleet, and other assets that generally correspond to the General Plant investment category. Table 1-2 provides a summary of the largest components of HOSSM's system.

Table 1-2 HOSSM Electrical Assets Overview

System Components	Counts / Units
Transmission Lines (560 circuit km of overhead assets): Conductor and ancillary equipment supported by a mix of Wooden, Composite and Steel Structures.	
230 kV Lines	318 cct. km
115 kV Lines	232 cct. km
44 kV Lines*	11 cct. km
Transmission Stations (15 stations): 230/115 and 115/44 kV stations of various configurations, equipped with 1 to 3 power transformers and other standard operating and safety equipment.	
Station Transformers	20
Circuit Breakers	105
Switches	156
Protection Relays	338
Circuit Switchers	5
Shunt Reactors	3
Capacitor Banks	2

**HOSSM's 44 kV lines and equipment have been deemed by the OEB as serving transmission function under Section 84 of the Ontario Energy Board Act, 1998.*

In addition to the transmission line and station equipment, HOSSM owns and operates several other asset classes, including fibre optic equipment within the station sites, SCADA equipment, radio communication equipment for crew use, computer software and hardware, testing equipment, and office implements. HOSSM currently leases the space for its head office and operating centre, and operates a small fleet of vehicles, including one bucket truck, 18 trucks and SUVs, six snowmobiles, and six off-road vehicles.

1.3 CAPITAL EXPENDITURES SUMMARY

For the 2018-2026 Plan period, HOSSM plans to manage capital expenditures within the funding envelope provided by the depreciation funding embedded in the last (2016) rebasing proceeding, adjusted through application of the annual Revenue Cap Index. For further discussion on the Revenue Cap Index see Exhibit D, Tab 1, Tab 1. The following Table 1-3 provides the breakdown of Historical and Plan period capital expenditures for the period covered in this TSP.

Table 1-3: Historical and Plan Period Capital Expenditures Summary

	Historical					Plan									Total Plan
Category ($M)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	
System Access	$0	$0	$0	$0	$0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4	$3.4	$0.0	$0.0	**$4.8**
System Renewal	$2.3	$3.3	$7.1	$6.5	$10.2	$5.1	$3.0	$8.0	$7.9	$5.9	$7.6	$7.1	$8.7	$7.8	**$61.0**
System Service	$0.6	$0.2	$0.1	$0.5	$0.7	$1.3	$1.3	$2.6	$2.8	$5.5	$0.3	$0.3	$1.6	$0.6	**$16.0**
General Plant	$0.5	$0.5	$1.3	$1.9	$4.1	$0.1	$2.9	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	**$3.9**
Total	**$3.3**	**$4.0**	**$8.5**	**$8.9**	**$15.0**	**$6.5**	**$7.1**	**$10.7**	**$10.7**	**$11.5**	**$9.4**	**$10.8**	**$10.4**	**$8.5**	**$85.7**

To enable comparative analysis, HOSSM mapped its historical expenditures and those made by its predecessor to the OEB's RRF investment driver categories. The Plan period expenditures represent the project and program scopes that HOSSM and Hydro One developed jointly using the system data on HOSSM asset condition, demographics, criticality, along with results of customer engagement and regional planning work.

As discussed in Section 1.1 the current Plan reflects the state of the integration work between HOSSM and Hydro One. As integration work continues over the Plan period, HOSSM may amend the scope, timing or sequencing of the projects contained in the work program due to emergence of new information pertaining to performance, condition or other operational characteristics of HOSSM's system. Other factors that may lead to incremental plan amendments include management's decisions related to scope and nature of outstanding consolidation activities, the results of the upcoming 2019 Regional Planning Process, future customer engagement activities, and other events that may occur in the normal course of system operation.

In undertaking any material updates to the Plan over its course, HOSSM will leverage the Asset Risk Assessment ("ARA") and Investment Planning Process ("IPP") frameworks. Notwithstanding potential updates, and subject to unforeseen circumstances beyond HOSSM's control, the company plans to manage the funding for the Plan period capital projects within the funding envelope displayed in Table 1-3.

1.4 KEY EXPENDITURE DRIVERS

For the purposes of this Plan, HOSSM has aligned its historical and planned capital expenditures with the four investment driver categories prescribed by the OEB's RRF policy. Table 1-4 provides an overview of investment categories including drivers, work program activities, investment examples and planned expenditures over the 2018-2026 Plan timeframe.

Table 1-4: 2018-2026 TSP Investment Categories Overview

Investment Category	Expenditure Drivers	Representative Activities	Investment Examples	Plan Total ($M)
System Access *ISD# SA-01*	Customer Requests	Customer Connections, Service Upgrades	Echo River TS spare Transformer Installation.	**$4.8** *6%*
System Renewal *ISD# SR-01 to SR-08*	Asset Failure	Reactive replacement of assets failed in service	No planned projects.	**$61.0** *71%*
	Assets at the End of Life due to Condition, Failure Risk, or Functional Obsolescence	Wood Structure and Conductor Replacements, Transformer and Relay Replacements.	Sault #3 Line Upgrade; Wood Structure Replacements; MacKay TS Relay Replacements.	
System Service *ISD# SS-01 to SS-04*	System Reliability and Operational Efficiency Improvements	Station Consolidation, Protection and Control enhancements	Greenfield TS Station Consolidation, Relay Replacement Program	**$16.0** *19%*
General Plant *ISD# GP-01 to GP-03*	Non-system physical plant and computer software.	Land Acquisition for Station Expansion; IT and Fleet Replacement. Ongoing upkeep of fleet and IT assets, real estate needs to enable station consolidation	Third Line TS Storage Building, Greenfield TS Land Purchase	**$3.9** *5%*

System Renewal, comprised of planned replacements of both station and line assets found to be in deteriorating condition or otherwise determined to require intervention on the basis of system data, represents the largest portion (71%) of total planned expenditures over the 2018-2026 timeframe.

System Service investments, include a planned consolidation of two existing stations (Batchawana and Goulais TS) into a new Greenfield TS. Projects to upgrade or reconfigure existing station assets and upgrade a number of Protection Relays, is the second largest investment category, representing approximately 19% of planned expenditures.

System Access and **General Plant** make up the remainder of the anticipated Plan period expenditures, combining to ten percent of the total planned capital spend. System Access category entails a single planned project to procure a spare transformer to provide contingency support in the event of a failure of a single existing transformer at the Echo River TS. General Plant investments include a planned acquisition of a land parcel for the construction of the consolidated Greenfield TS, and funds to facilitate routine upgrades and replacements of HOSSM's Information Technology and Fleet infrastructure. For a comparison between the Historical and Plan period investments, refer to Section 2.1.

The current Plan does not contain any projects that are proposed to enable future integration of renewable generation sources into the HOSSM system. As confirmed by the letter from the IESO provided in Appendix A, the last (2014) iteration of the Regional Planning Process for the East Lake Superior Region where the entirety of HOSSM's system is situated, did not identify any projects that required coordinated planning. However, the planning process did identify three "wires-only" solutions involving the lead transmitter (HOSSM's predecessor Great Lakes Power Transmission LP) and the impacted customers. One of the three projects, namely the installation of a spare transformer at the Echo River TS is included in this Plan, with the other two solutions awaiting further decisions on the part of the customers involved.

1.5 SIGNIFICANT CHANGES TO THE ASSET MANAGEMENT PROCESS

By virtue of acquisition of HOSSM’s predecessor GLPT by Hydro One Inc. and through the ongoing integration with Hydro One’s Asset Management function, the investments comprising this plan underwent assessment using a similar asset management and investment planning processes employed by the acquiring utility, modified to reflect the current state of integration of the two entities’ information technology systems and the availability of pertinent data. See Section 2.2.2 for a detailed description of the new elements of the asset management process reflected in this Plan.

1.6 ANTICIPATED SOURCES OF EFFICIENCIES

Over the 2018-2026 Plan period, HOSSM expects to fully integrate the operational, financial, and strategic dimensions of its business with Hydro One. HOSSM expects to identify and realize operating and capital efficiencies in a number of functional areas and expects to use the resulting efficiencies to manage the capital program within the envelope provided by the Revenue Cap Index-adjusted depreciation funding, as unanticipated expenditure drivers may emerge over the nine-year Plan period.

Among the operating areas where HOSSM expects to leverage opportunities for efficiencies are the areas captured in Table 1-5.

Table 1-5 Summary of Anticipated Sources of Efficiencies

Operating Area	Type of Benefits Targeted
Grid Operations Control	Labour and Technology efficiencies through consolidated operations with Hydro One's Ontario Grid Control Centre ("OGCC").
General Plant Assets	Utilizing Hydro One's programs and management frameworks in managing Fleet, IT, Construction and Testing Equipment.
Supply Chain and Procurement	Leveraging Hydro One's volume-based price structures and strategic sourcing capabilities to realize equipment and materials cost advantages.
Contractor Efficiencies	Exploring favourable contractual arrangements with third-party service providers using Hydro One's strategic alliances, or relying on its internal resources, as applicable.
Capital Program Efficiencies	Consolidation of Station footprint, reactive maintenance spend management, and other operating efficiencies targeted by the proposed capital program.

See Section 2.2.3 for additional information on the anticipated sources of efficiencies HOSSM expects to explore and leverage over the Plan period.

2.0 TRANSMISSION SYSTEM PLAN

This section provides a general overview of the Transmission System Plan, including the information on key sources of planning inputs, changes to the asset management process, and the anticipated sources of efficiencies over the planning period.

2.1 TRANSMISSION SYSTEM PLAN OVERVIEW

HOSSM submits this standalone 2018-2026 TSP in support of its 2019 Revenue Cap Incentive Rate-setting application, to demonstrate the progress made in the area of system planning, and the initial stages of integration of HOSSM's and Hydro One's asset management functions. This Plan's submission also responds to the OEB direction for HOSSM to file a comprehensive TSP as per an outstanding settlement commitment made in a prior proceeding by its predecessor, GLPT.[3]

As a part of the ongoing integration efforts within the Asset Management and Investment Planning functions, the investment programs and projects comprising this Plan underwent analysis and prioritization using parts of Hydro One's enhanced multi-stage investment planning process, including the ARA and IPP processes described in more detail in Section 3.1.3. As a result of these recent efforts, the current plan combines the expert knowledge of HOSSM's asset management staff as to the state and performance of assets in their care, and the additional analytical rigour of Hydro One's recently enhanced IPP framework. Table 2-1 provides the historical capital expenditures made by HOSSM and the forecasted expenditures for the Plan period.

Table 2-1: HOSSM Historical and Planned Capital Expenditures Summary

	Historical					Plan									Plan Total
Category ($M)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Plan**
System Access	$0	$0	$0	$0	$0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4	$3.4	$0.0	$0.0	**$4.8**
System Renewal	$2.3	$3.3	$7.1	$6.5	$10.2	$5.1	$3.0	$8.0	$7.9	$5.9	$7.6	$7.1	$8.7	$7.8	**$61.0**
System Service	$0.6	$0.2	$0.1	$0.5	$0.7	$1.3	$1.3	$2.6	$2.8	$5.5	$0.3	$0.3	$1.6	$0.6	**$16.0**
General Plant	$0.5	$0.5	$1.3	$1.9	$4.1	$0.1	$2.9	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	**$3.9**
Total	**$3.3**	**$4.0**	**$8.5**	**$8.9**	**$15.0**	**$6.5**	**$7.1**	**$10.7**	**$10.7**	**$11.5**	**$9.4**	**$10.8**	**$10.4**	**$8.5**	**$85.7**

[3] Ontario Energy Board, EB-2016-0356, *Decision and Order, Hydro One Sault Ste Marie LP Application for Electricity Transmission Revenue Requirement effective January 1, 2017*. September 28, 2017, p. 10

HOSSM's first comprehensive TSP filing provides a comparative perspective, by aligning both its historical and planned capital expenditures with the four investment driver categories prescribed by the OEB's RRF policy: System Renewal, System Service, System Access, and General Plant. Specific project and program expenditures underlying the Plan period forecast are contained in the Investment Summary Documents provided in Section 4.9. The following passages provide an overview of investments comprising each of the four categories for the Plan period, along with a comparison relative to the historical investments.

System Renewal:

Over the 2018-2026 Plan period, System Renewal represents the largest investment driver, amounting to approximately $61.0 million or 71% of the forecasted expenditures. Among the work program activities comprising the System Renewal budget are replacements of wooden support structures, conductor segments, transformers, and other types of station equipment found to be in deteriorating condition, exhibiting known operational or reliability performance issues, or otherwise determined to warrant replacement over the nine-year Plan period. Average annual planned System Renewal expenditures amount to approximately $6.8 million.

As Table 2-2 on the following page showcases, nearly 70% of Plan period System Renewal expenditures are dedicated to Line equipment, particularly replacement of deteriorated wooden support structures, conductor and the ancillary equipment. Approximately 10% of Plan period System Renewal expenditures are dedicated to power transformer replacements, with the balance targeting Station Breakers and Switches.

HOSSM notes that the breakdown by "equipment category" provided in Table 2-2 aims to provide further clarity as to the main types of equipment that the projects in the System Renewal category target. However, since the scope of work within a number of projects calls for replacement or modification of other line and station equipment, the breakdown should not be interpreted as a forecast of capital additions by asset class.

Table 2-2: Plan Period System Renewal Investments by Equipment Category ($M)

Equipment Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	Percentage
Lines	$5.1	$3.0	$7.0	$7.0	$4.0	$4.0	$4.0	$4.0	$4.0	$42.1	69%
Power Transformers	$0.0	$0.0	$0.0	$0.9	$1.7	$2.7	$1.0	$0.0	$0.0	$6.2	10%
Breakers & Switches	$0.0	$0.0	$1.0	$0.0	$0.2	$1.0	$2.2	$4.7	$3.8	$12.8	21%
Total	**$5.1**	**$3.0**	**$8.0**	**$7.9**	**$5.9**	**$7.6**	**$7.1**	**$8.7**	**$7.8**	**$61.0**	**100%**

Compared to the historical period of System Renewal investments (2013-2017) showcased in Table 2-3, the total Plan period System Renewal expenditures are $31.6 million, or 108% higher than the historical period expenditures. The increase in the magnitude of investments is largely due to a longer plan period (nine years) relative to the five-year historical period. When compared on the basis average annual expenditures, the Plan period System Renewal expenditures of $6.8 million are 15% higher than the corresponding historical period figures of $5.9 million per year.

Table 2-3: Historical System Renewal Spend by Major Equipment Category ($M)

Equipment Category	2013	2014	2015	2016	2017	Total	Percentage
Lines	1.9	3.1	5.9	3.4	4.7	19.0	64%
Power Transformers	0.4	0.0	0.0	0.7	0.1	1.3	4%
Other Station Equipment	0.0	0.2	1.3	2.3	5.4	9.2	31%
Total	**2.3**	**3.3**	**7.1**	**6.5**	**10.2**	**29.4**	**100%**

The forecasted 15% increase in the average annual Renewal expenditures is primarily attributable to the fact that the Plan Period investments target replacement of larger (and more expensive) station assets such as transformers and breakers, whereas the station assets targeted in the last five years prioritized upgrades of ancillary electrical equipment, as shown in Table 2-3.

HOSSM plans to dedicate a larger of proportion of the Plan period System Renewal investments to line infrastructure and power transformer replacements, as the Asset Condition Assessment performed by METSCO (See Appendix B) confirmed that a material proportion of these asset populations are in a “Fair” condition or worse. Moreover, the Plan period line upgrade work includes replacement of conductor on the Sault Number 3 line, found to be in “Poor” condition based on the outcomes of a 2015 Kinectrics testing report (See Appendix C).

In terms of their share in the total Plan period expenditures, System Renewal assets represent 71% of the total forecast, compared to 74% in the historical period expenditures. This variance is largely attributable to a greater number of System Service projects over the Plan period, driven primarily by targeted operational and reliability performance enhancements. For a detailed description of material System Renewal projects, refer to the Investment Summary Documents SR-01 to SR-08 in Section 4.9.

System Service:

System Service investments are the second largest investment category over the Plan period, representing 19% of total forecasted investments ($16.0 million). The nature of planned System Service investments includes upgrades to Protection and Control (P&C) relay equipment at select stations that are functionally obsolete due to the lack of ongoing vendor support or known performance issues, reconfiguration of station infrastructure to enhance equipment reliability and operability, and a large project to consolidate two existing stations (Goulais and Batchawana TS) into a single Greenfield TS. These investments target enhancing system reliability, addressing equipment access issues that present safety hazards under specific operating conditions, and to replace equipment in deteriorating condition. For a detailed description of material System Service projects, refer to the Investment Summary Documents SS-01 to SS-04 in Section 4.9.

When compared to the historical period, Plan period System Service expenditures represent a significantly larger portion of total investments (16% versus 6%). Similarly, the average annual expenditures of $1.8 million over the Plan period are substantially higher than the $0.4 System Service investments over the last five years. This variance is largely due to the fact that Plan period System Service investments target larger station assets such as power transformers and breakers, whereas the historical period investments that HOSSM classified as System Service were related to smaller-scale projects, such as station P&C upgrades, installation of oil spill protection infrastructure, and other modifications to station civil infrastructure.

System Access:

Over the Plan period, HOSSM's capital expenditures in the System Access category amount to $4.8 million, or about 6% of the Plan total. These expenditures are related to a single project to procure a spare transformer for Echo River TS, where only one transformer is currently located. In the event of an outage to the single Echo River TS transformer, HOSSM's only available alternative for supplying the station load entails switching the affected load to a distribution-level emanating from Northern Avenue TS, the available capacity on which is insufficient to reliably support additional load during the peak consumption period. The solution to contingency issues at Echo River TS was among the three "wires only" alternatives identified in the course of the 2014 Regional Planning exercise.

Aside from the Echo River TS project, HOSSM does not currently anticipate undertaking any further System Access investments over the Plan period. Should prospective generation or load customers seek interconnection to the HOSSM transmission system, or existing customers seek enhancements of connection capacity in the future, HOSSM will process their requests in accordance with the relevant provisions of the Transmission System Code, and HOSSM's Transmitter License. Should these circumstances materialize, HOSSM will allocate the appropriate capital funding from within the existing funding envelope using the system planning methodologies described in Section 3.1.3.

HOSSM did not undertake any System Access investments over the historical 2013-2017 timeframe. While the 2014 Regional Planning exercise discussed in Section 2.3.1 identified two more "wires-only" issues involving specific customer needs associated with connection assets, both projects in question await further decisions on the part of HOSSM's customers. For a detailed description of the Echo River TS project, refer to the Investment Summary Document SA-01 in Section 4.9.

General Plant:

Over the 2018-2026 Plan period, General Plant investments included in the TSP amount to $3.9 million, or about 5% of the entire Plan period forecast. Planned expenditures include minor ongoing costs of upkeep of IT hardware and software, along with the purchase of a land parcel for the planned Greenfield TS, and a construction of a new storage facility on Third Line TS grounds to provide a centralized environmentally controlled location to house critical spares and other equipment.

The Plan period General Plant expenditures are 54% lower than the approximately $8.4 million of investments in this category made during the historical 2013-2017 period, which accounted for over 21% of total capital expenditures over that timeframe. The comparatively lower amount of planned General Plant expenditures reflects the anticipated efficiencies enabled through HOSSM's integration with Hydro One, and a smaller number of expected real estate transactions relative to the last five years. For a detailed description of material General Plant projects and programs, refer to the Investment Summary Documents GP-01 to GP-03 in Section 4.9.

2.2 KEY ELEMENTS OF THE TRANSMISSION SYSTEM PLAN.

This section summarizes the key components that make up the integrated TSP and contextualizes the quantitative and qualitative information provided throughout.

2.2.1 PERIOD COVERED AND VINTAGE OF THE INFORMATION

This TSP covers a five-year historical period of 2013 to 2017, and a nine-year Plan period from 2018 to 2026, inclusively. The information underlying this document is current as of July 1, 2018.

As noted throughout this document, this TSP provides a snapshot of utility integration activities that are presently ongoing and will proceed throughout much of the Plan period. As such, and notwithstanding the analytical rigour underlying the presently planned portfolio of investments, further integration may lead to amendments to the current Plan. Changes may occur as Hydro One asset management experts further their understanding of operating issues facing the HOSSM system, integration plans for equipment standards and work execution practices are implemented, or investment needs emerge through customer engagement, Regional Planning, or other external activities. HOSSM will manage the financial impact of any such changes within the funding envelope provided by the 2016 revenue requirement, adjusted annually by the Revenue Cap Index formula.

2.2.2 IMPORTANT CHANGES TO THE ASSET MANAGEMENT PROCESS

This TSP reflects a number of important enhancements to HOSSM's Asset Management Process, relative to its last submission for the 2017 revenue requirement adjustment (EB-2016-0356). Most notably, the enhancements manifest themselves in the form of this first integrated Transmission System Plan, developed in accordance to the OEB requirements and consisting of the following core components:

- HOSSM's first *Comprehensive Asset Condition Assessment ("ACA")* was prepared by METSCO (see Section 3.2.2 and Appendix B) covering HOSSM's major asset classes and utilizing the full extent of available inspection and testing information to develop robust multi-factor asset Health Indices, grounded in quantitative results of multiple technical assessments, including the following subset (as applicable):
    - Transformer and Breaker Oil Dissolved Gas Analysis ("DGA:);
    - Insulation Power Factor Tests;
    - Infrared Scanning;
    - Breaker Timing Tests;
    - Wood Structure Remaining Strength Tests; and,
    - Physical Condition Inspections.

- *Hydro One's Asset Risk Assessment ("ARA")* Process, building on the findings of the ACA, and incorporating asset needs and risk evaluation along the additional planning dimensions, including Demographics, Criticality, Performance, Utilization, and Economics, were employed to yield a comprehensive evidence-based evaluation of the risks underlying the recent state of HOSSM's system assets (see Section 3.1.3.2 for a detailed description of the ARA framework as applied to HOSSM work program).

- *Investment Planning and Prioritization ("IPP") Process* recently implemented by Hydro One, to assess each proposed investment on the probability and consequence of Reliability, Safety and Environmental risks, enabling HOSSM to prioritize among the candidate projects on the magnitude of risk they are expected to mitigate (see Section 3.1.3.3 for a detailed description of the IPP process). In addition to the above-noted enhancements to the planning process underlying the proposed investment portfolio, the TSP incorporates several other critical components, including the findings of the latest Regional Planning Process for the East Lake Superior Region, and the outcomes of the engagement with HOSSM's customers (discussed in Sections 2.3.1 and 3.1.3.2, respectively). In aggregate, the combination of these factors yields an evidence-based integrated system plan that combines analytical rigour of multi-dimensional quantitative analysis, expert knowledge of operating issues affecting the HOSSM system on a daily basis, and the outcomes of engagements with key stakeholders.

2.2.3 ANTICIPATED SOURCES OF EFFICIENCIES

Over the 2018-2026 Plan period, HOSSM expects to fully integrate the operational, financial, and strategic dimensions of its business with Hydro One. In the process of integration activities, HOSSM expects to identify and realize operating and capital efficiencies that would enable it to maintain its planned capital spend within the revenue requirement envelope.

While certain operational integration milestones have already been achieved, the majority of this work will take place over the coming years as HOSSM operating standards and practices are aligned with those of Hydro One and the work program, planning and execution functions are consolidated into a single process flow for Hydro One’s entire transmission system.

HOSSM notes that realization of efficiencies inherent in company mergers is a process that usually requires both time and up-front investments to consolidate planning and operations, align standards and nomenclature, and facilitate appropriate onboarding work for the incoming workforce. In areas where the two entities’ equipment standards or operating practices may not presently align, the integrated utility may be required to maintain larger inventories or facilitate duplicative operating processes until such time that full alignment can be achieved. Accordingly, the pace, scale and scope of targeted benefits will depend on a number of strategic and operational factors that are currently being explored by both entities.

A number of capital investments included in the current HOSSM TSP are also expected to yield operating efficiencies through planned consolidation of the transmission station footprint, and replacement of assets requiring additional maintenance effort relative to the targeted new replacement unit designs and technologies. The following passages provide an overview of the areas where HOSSM and Hydro One expect to achieve financial benefits to help the utilities maintain the planned nine-year capital program within the envelope of available capital funding:

Grid Operations Control

The 24/7 operation of HOSSM's transmission assets was officially integrated with Hydro One's Ontario Grid Control Centre ("OGCC") on February 5, 2018. However end-point solution will not be in place until the first quarter of 2019. The integration allows HOSSM to forgo the otherwise planned investments for a backup Control Centre infrastructure, along with capital investments into regular upkeep of the main Control Centre and the associated IT equipment, along with operating efficiencies associated with Control Centre labour expenditures.

General Plant

Among the advantages of HOSSM's ongoing integration with Hydro One are the scale of Hydro One's transmission operations and the proximity of its operating assets to those of HOSSM's. Given these positive factors, HOSSM and Hydro One both expect to achieve efficiencies in the following areas:

- *Fleet Utilization and Maintenance:* Avoided procurement costs of new vehicles, increased utilization of Hydro One's existing fleet, vehicle maintenance savings and parts/fuel procurement leveraging Hydro One's processes and procurement contracts.
- *Field Equipment Utilization:* To date, HOSSM has largely relied on outside contractors for certain types of specific construction, testing, and maintenance equipment to undertake its work program. As a part of the integration, Hydro One and HOSSM will explore economically optimal arrangements for future use of special equipment in light of Hydro One's inventory and fleet, its current operating practices, and both entities' projected needs in the area.
- *IT Hardware and Software*: The operational integration between the two entities provides an opportunity to explore and leverage potential efficiencies in the areas of procurement, maintenance, and licensing of HOSSM's IT software and hardware assets.
- *Tools, Spare Parts and Implements*: Similar to other types of equipment, Hydro One's scale advantages enable HOSSM to realize efficiencies in procurement of small tools and implements, spare parts for standard equipment, fire-resistant clothing, and small sundry items used by construction and maintenance crews in their daily operations.

Supply Chain and Procurement

Along with procurement efficiencies for some of the smaller items noted above, integration will allow HOSSM to leverage the full extent of the Hydro One's Supply Chain capabilities, including strategic sourcing, supplier performance management frameworks, and volume-based discounts, among others.

In the cases where materials and equipment standards are not currently aligned, the anticipated benefits may not materialize until sometime into the integrated utility's existence. In the interim, it is possible that HOSSM may be required to maintain an inventory of spare parts and/or supplier relationships for procurement of certain equipment, which may delay the realization of targeted benefits. In the long run, however, the benefits of Hydro One's scale can be expected to provide positive benefits when compared to the costs of past operations.

Contractor Labour Efficiencies

Given its relatively small staffing complement, HOSSM has historically relied on third party supplier labour for a number of capital work execution tasks, maintenance and equipment testing services, and preparation of planning and engineering studies, among other activity areas. As with equipment and materials, the ongoing integration will enable HOSSM to explore opportunities for leveraging a larger labour force and more preferential contractual arrangements. The scope, scale and timing of these potential efficiencies will depend on multiple factors; including the terms of the existing arrangements and the availability of internal Hydro One resources to undertake previously contracted work.

Capital Equipment Efficiencies

Beyond the efficiencies related to GLPT's acquisition by Hydro One, several projects included in the 2018-2026 Plan are set to provide operational benefits in the form of reduced maintenance requirements. Examples of projects that HOSSM expects to yield maintenance efficiencies include:

<u>Oil Circuit Breaker replacements at Steelton TS</u>, which require more frequent maintenance than the newer circuit breaker technologies, and in the particular case of Steelton TS, mandate additional isolation of the surrounding equipment due to the station's spatial configuration. Replacing these functionally obsolete units will enable HOSSM to reduce the frequency of breaker maintenance and streamline the number of steps associated with each maintenance procedure.

<u>Replacement of assets with known operational issues</u>, such as the switchgear racking mechanism at Watson TS (an implement that enables the individual breakers to be moved within individual switchgear cubicles). In the case of servicing the particular Watson TS unit, HOSSM operating personnel have encountered multiple issues in attempting to operate the mechanism, leading to longer regular maintenance activities, and presenting a risk in the event of an emergency intervention being required. Replacing the defective racking mechanism as a part of a larger upgrade project planned at Watson TS will reduce the time required to service the assets.

<u>Consolidation of Batchawana TS and Goulais TS into a single Greenfield TS</u>, leading to anticipated reduction in average maintenance expenditures (inspections and preventative work would no longer require two separate crew trips), avoidance of scheduled outages which are currently required to conduct transformer maintenance at both stations, and physical consolidation of common station equipment.

In a similar manner, the continued replacement of wood structures in poor condition with composite fiberglass structures can be expected to yield benefits from the perspective of regular maintenance expenditures management and asset lifecycle extension, as composite poles are far less susceptible to woodpecker damage, which erodes the structural integrity of support structures and requires additional maintenance to patch up the resulting holes using a special solution.

Along with anticipated benefits to the regular maintenance practices, HOSSM also expects a number of System Renewal and System Service investments to yield positive benefits on the reactive maintenance expenditures, particularly where replacements and upgrades are made to equipment in deteriorated condition. This is a particularly relevant consideration for assets in the more remote part of HOSSM's service area such as Watson TS, where a trouble call requires crews to travel for up to several hours, leading to prolonged outages and additional labour expenditures.

Similar considerations apply to upgrades and replacement of P&C equipment that is no longer supported by vendors, and for which spare parts are increasingly difficult to procure. By replacing a number of functionally obsolete relays with a history of mis-operations, HOSSM seeks to reduce the risk of prolonged outages (and their associated costs), while also reducing the time and effort involved on the part of Supply Chain in procuring spare parts for units that are no longer readily available for purchase.

Further efficiencies may be available in relation to future planned projects where a more in-depth integration of HOSSM's asset management practices with those of Hydro One may reveal opportunities for project scope reductions, deferral, or cancellations in the areas where the application of Hydro One's corporate asset management standards (once these are fully applied to planned HOSSM investments) suggest an alternative form or timing of intervention. An example of this approach already incorporated into the Plan is the replacement of bushing gaskets on power transformers at Clergue TS, which addresses a key driver of their relatively low condition scores as per the METSCO ACA (61% and 54% Health Index respectively), while enabling HOSSM to forgo their replacement during the Plan period.

While the current plan has already benefitted from the application of Hydro One's ARA and IPP frameworks, certain aspects related to operating and planning practices, such as work bundling standards for station upgrade planning, cannot be responsibly applied until Hydro One's asset management, investment planning, and work execution professionals have had the benefit of extensive exploration of HOSSM's current practices and particularly the operating issues experienced in the field.

Other Potential Efficiencies

Beyond the functional areas described above, the ongoing integration of operations is expected to yield benefits in other areas, such as front/back office, customer care, and others. While integration work is ongoing in these and other relevant areas, HOSSM will forgo their discussion given that they are not directly relevant to the primary focus area of this system planning document.

2.2.4 TSP CONTINGENCIES

Successful execution of the projects comprising the 2018-2026 work program is contingent on a number of internal and external factors discussed below:

Weather / Climate-Related Challenges

The majority of System Service and System Renewal work underlying the planned capital work program require planning and coordination of outages on the relevant portions of the HOSSM system. Given the increasingly volatile weather patterns observed in recent years, HOSSM's ability to plan for and execute the requisite outages may be affected by the local, regional and inter-area transfer capability constraints that may emerge as a result of unpredictable weather patterns such as abnormal temperatures, major storms, or water levels affecting the operations of hydroelectric generators directly connected to the HOSSM system.

Beyond outage scheduling, weather volatility may also affect the timing of execution of planned structure and conductor replacements, particularly in the more remote areas of HOSSM's system given the access and staging complexities that characterize work execution in these areas even during normal weather conditions. HOSSM will address these work execution issues through close coordination and communication with its generation and load customers, the contractor community, Hydro One and the IESO grid control functions.

Regional Electricity Infrastructure Requirements

Although the most recent, 2014 East Lake Superior Regional Planning Process did not identify any specific need for regional coordinated planning[4] (See Section 2.3.1 for further details on Regional Planning), the next cycle of the Regional Planning Process is set to commence in 2019. Should this planning activity identify any need for coordinated regional planning such as the execution of Scoping Assessments or the Integrated Regional Resource Plans, HOSSM will actively participate in these processes and work with the IESO and other affected stakeholders to coordinate this work with its own capital plans.

Scope, Nature and Timing of Ongoing Integration Activities

As the comprehensive integration of asset management policies, technical equipment standards, and work execution practices between Hydro One and HOSSM continues over the coming years, certain projects comprising the current plan may be amended in terms of their scope and timing, or de-prioritized in favour of other projects that may present a greater economic value proposition or the potential to mitigate a greater degree of risk exposure based on emerging circumstances over the plan's nine-year horizon.

While the currently formulated plan is grounded in comprehensive evidence-based assessments, certain aspects of current plans (e.g. choice of particular equipment or materials, the manner of work bundling) reflect the existing policies and practices of HOSSM, which continues operating as a separate entity until October 1, 2018. Following the formal commencement of integrated

[4] While the Regional Planning Process did not identify any projects requiring coordinated planning, it did reference three "wires-only" solutions involving HOSSM's predecessor and particular customers. One of these projects, the Echo River TS Spare Transformer is included in this TSP (ISD #SA-01 in Section 4.9).

operations, the timing of further integration activities will be assessed relative to other business process consolidation priorities.

Property Rights and Access-related Considerations

Several programs outlined in the current plan rely on HOSSM obtaining access and easement rights or purchasing parcels of land in the areas where construction work is planned. To the extent that HOSSM is unable to secure these property or access rights within the timelines contemplated in the project plans, it may adjust the project timelines or explore alternative locations or asset configurations as appropriate. As with any real estate transaction, HOSSM will make best efforts to consult with all the affected parties and coordinate the arrangements that balance stakeholder needs, economic efficiency, technical safety, and system needs.

Customer or Third-Party Requests

HOSSM's ability to deliver the currently planned capital work program within the contemplated scope and timelines may be affected by requests from current or prospective customers, along with third parties, that may approach HOSSM with requests to execute certain projects (e.g. existing infrastructure relocations, new connections or enhancements). Should these requests emerge, HOSSM will work with the requesting parties and other affected stakeholders to reasonably accommodate all requests in accordance with the applicable provisions of the Transmission System Code.

Other Contingencies

Other contingencies that may affect HOSSM's execution of the current plan include but are not limited to:

- government and OEB policy amendments;
- changes to IESO/NERC/NPCC policies, procedures, or technical requirements;
- disputes with third parties; and
- other factors.

HOSSM accepts these risks and will actively manage them through regular engagements with policymakers, industry organizations, employees, customers and the contractor community.

2.3 COORDINATED PLANNING WITH THIRD PARTIES: SUMMARY OF INPUTS AND ENGAGEMENT EFFORTS

2.3.1 REGIONAL PLANNING PROCESS

The entirety of HOSSM's transmission system is located within the East Lake Superior Regional Planning Zone depicted in Figure 2-1. The region includes all of HOSSM's 560 circuit km of transmission lines, along with ties to the provincial grid at Hydro One's Wawa TS and Mississagi TS, and a Hydro One 115 kV line supplied from Wawa TS.

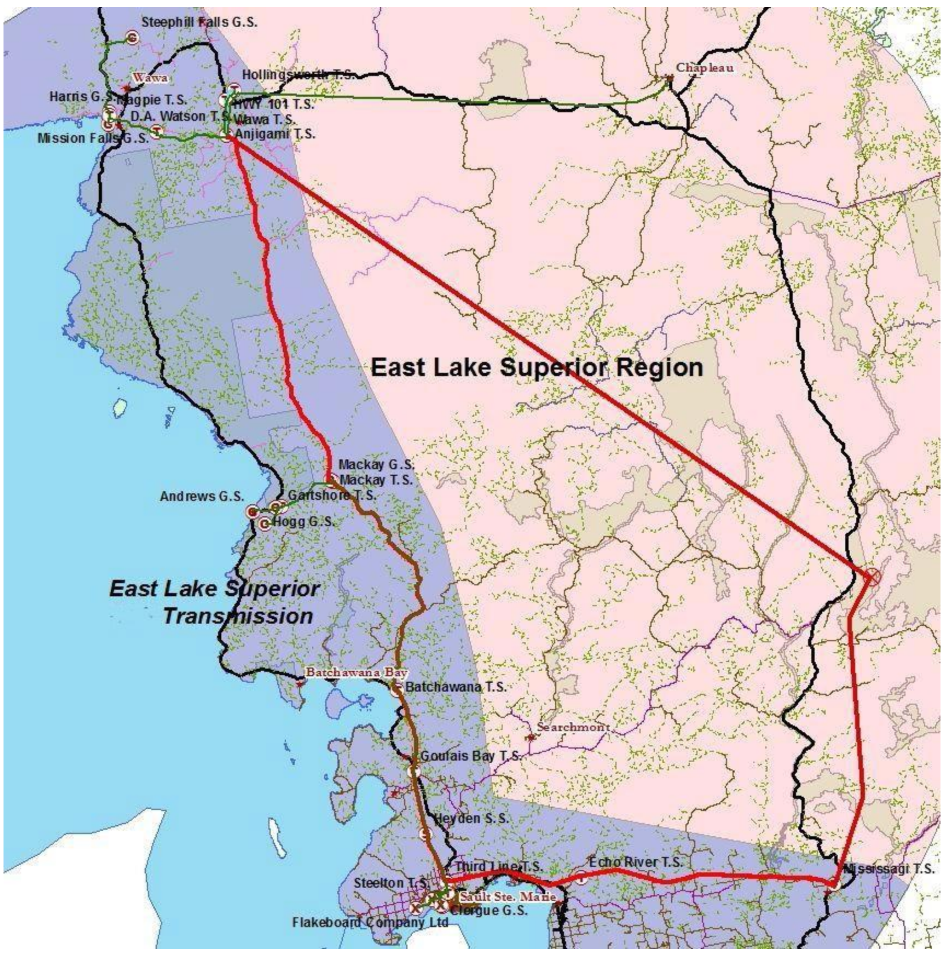


Figure 2-1. East Lake Superior Planning Region

There are three Local Distribution Companies in the region, namely Algoma Power Inc., and PUC Distribution Inc., supplied by HOSSM, and Chapleau Public Utility Corporation supplied by Hydro One. As the lead Transmitter, HOSSM's predecessor GLPT, along with representatives from Hydro One, IESO and the three distribution utilities in the region conducted a needs assessment process (see Appendix D), which explored the potential for coordinated planning solutions to any anticipated issues over the study's ten-year outlook period. The participants shared load forecasts, Conservation and Demand Management ("CDM") plans, and targeted capital sustainment activities over the relevant planning horizon.

The findings of the planning process culminated in a December 12, 2014 Needs Assessment Report (Appendix D), which concluded that there was no anticipated need for coordinated regional planning work over the study period. The report also stated that no capacity issues were identified on either the 230 kV or 115 kV connection facilities, or the 230/115 kV autotransformers.

The parties participating in the process identified three localized, "wires-only" issues, two of which involved issues associated with potential modifications to customer connections to the GLPT system, with the third involving load restoration issues at GLPT's transmission stations equipped with a single transformer, where outage incidents may result in violation of the Ontario Resource and Transmission Assessment Criteria ("ORTAC") 8-hour (plus travel time) load restoration standard.

This Plan contains a project to address one such station through the addition of a spare transformer – namely the Echo River TS Spare Transformer project (See ISD #SA-01 in Section 4.9). The Plan also includes a project to consolidate two more stations presently equipped with a single operating transformer – Goulais TS and Batchawana TS, into a single station, enabling service continuity during contingencies and scheduled maintenance work, among other benefits (See ISD # SS-01 in Section 4.9).

As a part of the Regional Planning exercise, GLPT also shared its plans for material capital sustainment activities on nine of its fifteen stations; a number of which have been completed over the historical five-year period described in this plan, with others included in the forward-looking plan period investments, including upgrades at Watson TS, and consolidation of Batchawana and Goulais TS.

In preparing this Plan, HOSSM obtained a letter from the IESO (Appendix A), confirming that the 2014 process identified no need for regional planning, requiring no further actions such as the preparation of Scoping Assessments or the Integrated Regional Resource Plan. Consistent with the findings of the last Regional Planning Process, HOSSM's current TSP does not include any investments identified through this process. The next cycle of the Regional Planning work for the East Lake Superior region is scheduled to commence in 2019. HOSSM will participate in the process as the lead transmitter and incorporate any relevant findings into the subsequent iterations of this TSP as necessary.

2.3.2 SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE GENERATION

HOSSM transmission system serves as an injection point of a significant amount of renewable generation in the Ontario's bulk transmission system as the installed generation capacity directly connected to the HOSSM assets (699 MW) materially exceeds the system's peak load of approximately 300 MW in the summer months and 350 MW during the winter season. In addition to the transmission-connected generation, a total of about 195 MW of generation and storage capacity is embedded within the distribution systems of HOSSM's load customers. Table 2-4 provides a breakdown of the generation and storage sources connected to or embedded within the HOSSM system.

Table 2-4: Generation and Storage Capacity Connected to HOSSM System (MW)

Transmission-Connected Generation (MW)	
Hydroelectric	501
Wind	198
Subtotal: Transmission-Connected	**699**
Embedded Generation and Storage (MW)	
Steam Cogeneration	128
Solar	60
Storage	7
Subtotal: Embedded	**195**
Total (MW)	**894**

The existing generation and storage facilities are connected to the HOSSM system in a number of locations. Table 2-5 provides a summary of generation and storage capacity currently connected directly or embedded into the HOSSM system by station.

Table 2-5: Generation and Storage Capacity by Station (MW and MVAR)

Station / Subsystem	**MW**	**MVAR**
Anjigami TS Subsystem		
Magpie TS	43	48
Watson TS	80	85
Hollingsworth TS	24	30
MacKay TS Subsystem		
Garthshore TS	86	97
MacKay TS	60	63
Third Line TS Subsystem		
Third Line TS	223	248
Patrick St/Steelton TS	130	141
Clergue TS	52	55
Third Line TS - Embedded	195	213
Total	**894**	**980**

In facilitating connection requests from generation or storage customers, HOSSM follows the relevant provisions of the Transmission System Code and the conditions of its license, including those governing the preparation timelines of transmission Connection Impact Assessments (“CIA”s) and other steps comprising the connection process (including coordination with the

IESO for System Impact Assessments) that set out service standards for licensed transmission system operators.

At present, there are no outstanding applications by generators or storage providers seeking interconnection to HOSSM's transmission system. HOSSM is also not aware of any firm plans by potential or existing customers to seek additional connection capacity over the Plan period timeframe. Accordingly, this TSP does not include any investments related to capacity enhancements or other modifications to accommodate future interconnection of renewable generation or energy storage resources. Should the potential need for any such investments emerge over the Plan period, HOSSM will evaluate the pertinent information in the scope of Regional Planning work and specific connection requests, subsequently amending the TSP as required, using the planning processes discussed in Section 3.1.3.

2.3.3 FACILITATION OF GOVERNMENT POLICY OBJECTIVES ON CONSERVATION, RENEWABLES AND GRID MODERNIZATION.

HOSSM supports the Ontario government's policy objectives in the areas of conservation and demand management, promotion of renewable generation and storage, and grid modernization through the use of advanced analytics, automation, and emerging Smart Grid technologies.

As discussed in section 2.3.2, HOSSM is a host to almost 900 MW of renewable and industrial by-product (steam) generation and storage capacity, connected directly to its system or embedded within the distribution systems of its customers. Considering that this TSP contains plans for replacement or modification of a number of large assets, including work on the assets to which generation projects are directly connected, HOSSM will work closely with its generation and load customers and the IESO to coordinate the requisite outage work in a manner that minimizes the impact of outages required to conduct the transmission system work.

In continuation of the practices of its predecessor, HOSSM is not directly involved in administration of any industrial Conservation Demand Response programs. However, a number of HOSSM's load customers, including both licensed distributors (Algoma Power and PUC Distribution Inc.) and Essar Steel Algoma Inc. have implemented embedded generation and cogeneration solutions that help reduce their respective systems' demand on transmission assets operated by HOSSM. These efforts are in addition to conservation and demand management programs offered by both licensed distributors. HOSSM engages its customers with respect to their plans for conservation and demand management as a part of regular Customer Engagement activities and the Regional Planning Process where the parties jointly consider their individual and aggregate regional load forecasts.

HOSSM endorses the value of continued grid modernization, both by way of integrating emerging technologies into the operation of its system and increasingly relying on advanced evidence-based decision support tools in the process of system planning and asset sustainment. HOSSM understands that it was among the early adopters of using composite fiberglass poles in a transmission system for replacement of its wooden transmission support structures and has generally seen positive results associated with this practice. Moreover, this TSP is grounded in HOSSM's first comprehensive Asset Condition Assessment ("ACA") study performed by METSCO (see Section 3.2.2 and Appendix B) that has substantially enhanced the quantitative rigour underlying the preparation of the Plan.

In addition to the results of the ACA, HOSSM's TSP has benefitted from the application of two critical processes comprising Hydro One's Asset Management and System Planning process – namely the ARA and the IPP described in Sections 3.1.3.2 and 3.1.3.3 of this Plan. Through application of these advanced processes, the projects included in this Plan underwent comprehensive evaluation on the basis of multiple performance, condition, demographic and operating factors, and were subjected to Hydro One's enhanced risk-based investment evaluation. All of these incremental steps enhanced the rigour of HOSSM's planning process and represent examples of innovation in asset management on the part of the company.

As the integration of HOSSM's asset management and system planning functions continues along the broad plan outlined in Section 3.1.1, it will evaluate further opportunities for continuous improvement and innovation of its asset sustainment processes and operational practices.

3.0 ASSET MANAGEMENT PROCESS

This Chapter of the Plan describes the scope, nature and process mechanics of the planning and operations activities that comprise HOSSM's asset management function at this juncture of the utility's ongoing integration with Hydro One. As described further in this Chapter, the planning processes utilized in the preparation of this Plan reflect those in use at Hydro One. Activities are ongoing to align the operating elements of HOSSM's asset management process with those of Hydro One.

3.1 ASSET MANAGEMENT PROCESS OVERVIEW

The purpose of the Asset Management process is to ensure that the utility's asset base performs in a safe, reliable, and cost-effective manner, while maintaining compliance with all applicable legislative and regulatory requirements, technical standards, and is consistent with the needs and expectations of HOSSM's customers and regional planning zone stakeholders. HOSSM's Asset Management process includes activities performed by its engineering and planning, maintenance, customer engagement, work execution staff and contractors to enable safe, reliable and cost-effective operation of its transmission system.

3.1.1 IMPACT OF HOSSM / HYDRO ONE CONSOLIDATION

As a part of the ongoing integration between HOSSM and Hydro One, HOSSM's asset management process is being aligned with and consolidated into the processes of the acquiring utility. This consolidation work is proceeding along three overlapping phases:

- Phase 1: Current State Exploration and Medium-Term Planning
- Phase 2: Planning Process Consolidation
- Phase 3: Work Process Management and Execution Consolidation

Phase 1 of the integration work has been substantially completed. The scope of work for this phase included data collection, verification and digitization to populate Hydro One's asset management systems, and the subsequent formulation of a nine-year Transmission System Plan, using the combination of HOSSM's system planners' local knowledge and Hydro One's enhanced Asset Management process described in the sections that follow.

In the course of the planning work, planners examined HOSSM's existing system planning documents (including the outcomes of the 2014 Regional Planning Process), the field data regularly collected through maintenance and inspection work, trouble reports, reliability performance statistics, and the relevant third-party reports prepared by external contractors, including HOSSM's first comprehensive ACA study prepared by METSCO, discussed further in Section 3.2.2.

To facilitate the incorporation of the HOSSM system, Hydro One and HOSSM planners assessed the current state of the HOSSM assets using the planning and prioritization frameworks that Hydro One Networks employs in preparation of its own Transmission System Plans. This process included a comprehensive assessment of HOSSM's asset base using the core methodologies underlying Hydro One's ARA process for asset management needs identification, and the risk-based IPP assessment. Both of these frameworks, as they relate to the preparation of this TSP are described in more detail in Section 3.1.3.

Compounding the analytical rigour of the ARA and IPP frameworks was the input provided by experienced HOSSM engineers and Operations staff, intimately familiar with the issues characterizing performance of particular asset classes and system components. Supplementing the local perspective on system planning and operational issues was the feedback from HOSSM's customers, collected through Customer Engagement Sessions, which were attended by both HOSSM and Hydro One staff. The input received through customer engagement sessions is described in more detail along with other parts of the Asset Needs Evaluation process in the Section 3.1.3.2.

Rounding out Phase 1 of the integration work is the ongoing asset data transition undertaking, which entails digitization, review, cleansing and consolidation of HOSSM's asset management records in the format supported by Hydro One's ERP (Enterprise Resource Planning) IT system. As a part of performing this work, Hydro One and HOSSM staff has also assessed the current alignment in terms of the type and volume of asset data collected by both entities, which will inform the scope of subsequent steps of asset management integration activities.

Phase 2 of the integration activities involves in-depth analysis and development of implementation plans for consolidation of the processes underlying the asset management and investment planning functions, including the scope, nature and frequency of preventative maintenance, inspection and testing activities, consolidation of equipment standards, along with cross-training of HOSSM and Hydro One staff on the key strategic and operational planning processes. The key objective of this phase is the development of a critical path to enable full alignment of data and processes to ensure seamless operation across all asset management functions.

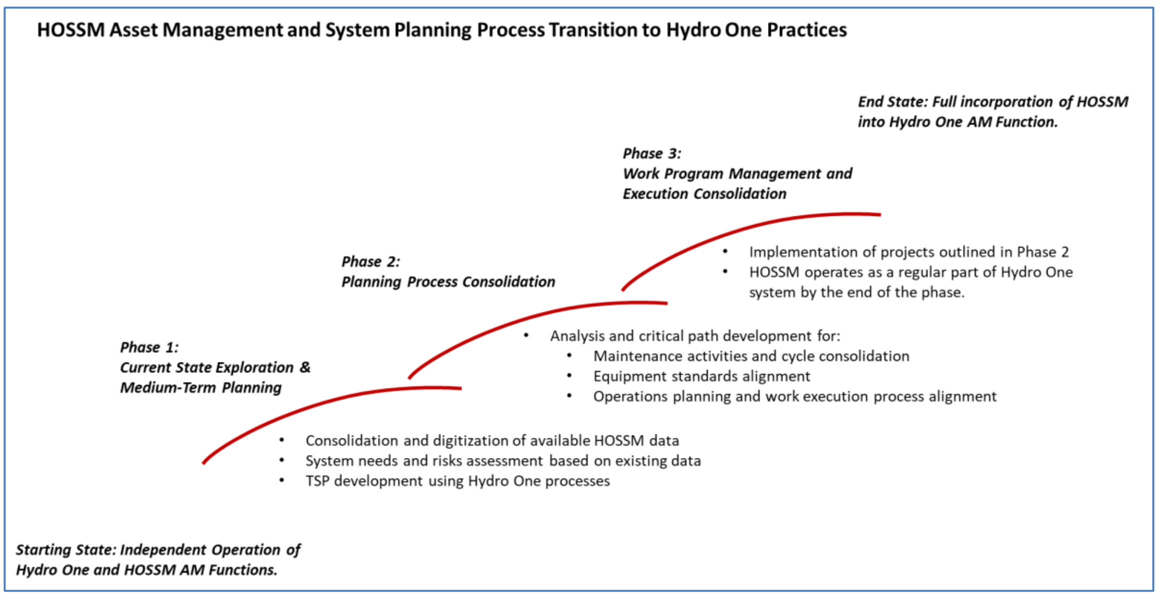


Figure 3-1: HOSSM Asset Management Function Integration Process

Phase 3 of the asset management function integration will include the full alignment of day-to-day work execution practices pertaining to planning, maintenance and capital work execution. In the course of this phase, Hydro One will execute the technical, organizational, and information technology projects identified on the integration critical path developed at the conclusion of Phase 2. By the conclusion of Phase 3, HOSSM and Hydro One's asset management practices are expected to be fully integrated across all asset management work planning and execution functions.

While the three phases of the asset management integration build upon incremental accomplishments on the way to full functional integration, the activities comprising each phase overlap in a number of instances. For example, the insights obtained from system needs analysis and customer engagement, along with results of ongoing operations, represent important inputs on the costing, sequencing, and pacing of the remaining integration activities. By monitoring the progress and results of the earlier activities, Hydro One is able to adjust its assumptions underlying the remaining integration steps.

3.1.2 ASSET MANAGEMENT OBJECTIVES

As the HOSSM system and operations supporting it will be progressively incorporated into the regular operating processes of the acquiring utility, HOSSM's asset management objectives for the duration of the Plan period can be summarized in the following manner:

Facilitate a smooth and cost-effective transition towards full adoption of Hydro One's policies and operating practices, in a manner that:

- maximizes the value of local expertise of HOSSM staff;
- maintains safe and reliable system performance;
- responds to the needs of HOSSM's customers; and
- ensures compliance with all applicable statutory and regulatory obligations.

These objectives are aligned with the OEB's RRF Outcomes, as articulated below:

1. **Customer Focus** – Services are provided in a manner that drives customer satisfaction and responds to customer needs and preferences, as gathered through consistent and continuous engagement activities.

2. **Operational Effectiveness** – Continuous improvement in productivity and cost performance to drive cost efficiencies inherent in the integration work, system planning objectives, and the delivery of system reliability and service quality outcomes while working toward maintaining an injury-free workplace.

3. **Public Policy Responsiveness** – Meeting the objectives mandated by government and regulators (e.g., through legislative and regulatory requirements), and sustainable management of our environmental footprint.

4. **Financial Performance** – Financial viability is maintained and savings from operational effectiveness are sustainable.

Throughout HOSSM's asset management processes, the above-noted objectives manifest themselves in the form of practical considerations that inform multiple dimensions of the IPP. As an example, Customer Focus, Operational Effectiveness and Public Policy Responsiveness outcomes correspond to specific risk quantification and calibration parameters (both quantitative and qualitative) underlying the risk trade-off analysis inherent in Hydro One's ARA and IPP frameworks.

The ARA process evaluates the state of the asset base to identify and prioritize the most pressing needs. The ARA process is grounded in considerations corresponding to both Operational Effectiveness and Customer Focus objectives, by focussing on factors such as asset condition, utilization patterns, criticality for service continuity and the economic implications of continued maintenance relative to replacement. The objectives of maintaining the utility's Financial Performance are reflected in the option analysis that takes place both in the context of the ARA and the IPP processes.

The planning process utilized in preparation of this TSP addresses the government's public policy objectives related to the promotion of renewable energy and smart grid technologies through consistent incorporation of needs, capabilities and risks (where applicable) of generation and energy storage customers connected directly to the HOSSM system or embedded within the systems of its customers. The total installed generation and storage capacity embedded or connected to the HOSSM system amounts to 894 MW. Issues related to the short-term and longer-term needs of HOSSM's generator customers represent an important planning consideration for the utility's asset management and investment planning processes, in the context of capital and operations planning, regional planning and customer engagement work. As described in Section 2.3.3, the planning process supporting this TSP is aligned with the government's objectives of grid modernization as articulated in the 2017 Long Term Energy Plan ("LTEP"). The alignment stems from the fact that HOSSM utilized advanced evidenced-based planning frameworks in developing this Plan, including risk-based analysis performed in the course of the IPP process.

Finally, employee and public safety – a planning dimension relevant to Operational Effectiveness, Public Policy Responsiveness and Financial Performance RRF outcomes – is among the key drivers of HOSSM's planning processes. A number of projects and programs, such as the planned consolidation of two existing transmission stations, Batchawana and Goulais, into a new Greenfield TS (Refer to ISD# SS-01), specifically incorporate asset improvements and modifications driven by employee safety, as the station will be built to respect the Limits of Approach for personnel and equipment as found in the Electrical Utility Safety Rules[5]. Moreover, every project and program included in this Plan underwent an assessment of its safety risk mitigation potential as a part of the IPP process, with projects that provide material safety benefits (such as improvement of clearances or replacement of leaking power transformers) receiving higher priority scores.

Overall, and as further elaborated in the remainder of this chapter, HOSSM's planning framework ultimately seeks to incorporate both qualitative and quantitative assessment parameters representative of all four OEB Outcomes and the corresponding asset management objectives throughout the asset management cycle – from asset planning, to maintenance, to the eventual replacement and decommissioning.

[5] Electrical Utility Safety Rule 129, Safe Limits of Approach, revised January 2014

3.1.3 ASSET MANAGEMENT PROCESS COMPONENTS

The key components of HOSSM's asset management process are positioned to maximize the achievement of its asset management objectives laid out in the preceding section.

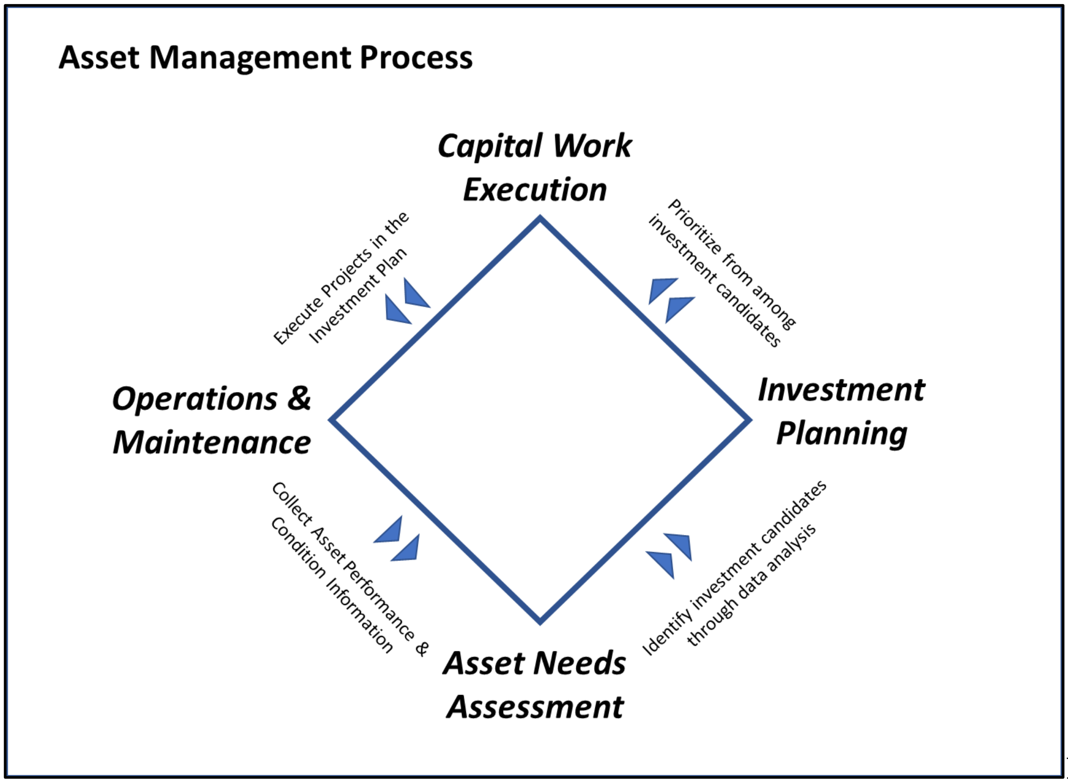


Figure 3-2: HOSSM Asset Management Process

Overall, the current TSP is a product of four complementary process components aimed at developing and executing economically optimal and operationally sustainable asset intervention plans supported by evidence-based decision-making. The components are:

- *System Operations and Maintenance*, consisting of planned and reactive activities supporting the safe and reliable operation of HOSSM's assets, and collection of field data used as input into the other dimensions of asset management work.
- *Asset Needs Evaluation*, which is the continuous application of Hydro One's ARA process, reflecting the current state of the HOSSM operational integration.

- *Investment Planning*, based on Hydro One's enhanced process for identification and quantification of asset risks across the Reliability, Safety and Environmental performance risk taxonomies.
- *Capital Work Execution*, which includes the design, construction, refurbishment and commissioning of HOSSM assets.

Each of the four components consists of multiple activities and sequential steps involving the application of discrete tools and processes and collection of inputs from multiple stakeholders. The information gathered and generated throughout this continuous feedback loop process forms the foundation of the TSP, which represents HOSSM's assessment of the current state of its system needs based on a range of available data, and a practical plan for meeting these needs in the context of relevant funding constraints, customer needs and preferences, and other external factors.

3.1.3.1 SYSTEM OPERATIONS AND MAINTENANCE

The System Operations and Maintenance ("O&M") component of the asset management process is comprised of multiple ongoing activities that ensure safe and reliable operation of the HOSSM system as a part of the Independent Electricity System Operator ("IESO")-controlled grid. These activities include:

- tasks related to the operational control of the HOSSM network;
- emergency response and dispatch functions;
- procurement, staging and distribution of materials, supplies and instruments;
- customer care;
- the upkeep of HOSSM's facilities and fleet, IT and communications equipment;
- maintenance of physical assets and transmission right of ways;
- tasks mandated by the conditions of HOSSM's Transmission License; and
- collection asset data that informs the near- and long-term system planning.

HOSSM performs these activities through the combination of internal staff and external contractor resources.

HOSSM employs a systematic approach for conducting inspections, testing, and executing preventative maintenance tasks (vegetation management, insulator washing, etc.) on a six-year cyclical basis, with some deviations for specific asset classes where more or less frequent maintenance is deemed necessary, or dictated by applicable statutory and regulatory requirements, such as the TSC or the North American Electric Reliability Corporation ("NERC").

In the process of inspection and testing work, HOSSM staff and contractors generate detailed reports, with all identified defects and performance issues subsequently logged, consolidated and prioritized for the purposes of planning and scheduling corrective action. In situations where observed performance issues warrant further examination, HOSSM conducts detailed technical studies performed by employees and/or third-party contractors specializing in the operation of specific assets.

In addition to the regular inspection and testing activities performed for line and station assets are the following:

- Component inspections of station asset condition (leaking corrosion, insulation, etc.), along with recording of readings of relevant instrument gauges, testing of operating mechanisms, resistivity and current measurements, etc.;
- Dissolved Gas Analysis ("DGA") testing for transformers, bushings, and oil breakers, measuring the presence and rate of change in particular gases and polymers that accumulate in oil throughout the equipment's lifecycle;
- Oil level and quality analysis, along with periodic oil reclamation work to ensure that oil condition is adequate for performing its dielectric and cooling tasks;
- Partial Discharge testing of insulation materials used in station equipment like transformers and switchgear;
- Thermographic Scanning of both station and line assets to identify and rectify any hotspots that emerge in the process of equipment's normal operation;
- Visual inspections of wood, composite and steel structures to assess their overall condition, degree of decay, remaining strength and damage caused by environmental exposure,

including rot, feathering, cracking, insect and woodpecker damage, corrosion, cross-arm condition, etc.; and

- Right-of-way inspections, facility inspections, and stations civil infrastructure inspections.

As good asset managers, Hydro One and HOSSM commissioned a comprehensive ACA report that included all major electrical plant asset classes and is found as Appendix B to the TSP. HOSSM used the results of the ACA to identify candidate investments based on the health index of the assets and also assets requiring follow-up examination over the planning period. Information gathered was also used to validate assumptions made in other stages of the planning work.

In addition to the asset condition data, HOSSM collects and monitors a number of performance parameters captured by its SCADA system (power flow, quality and fault data) and reliability statistics captured by its Outage Management System ("OMS").

3.1.3.2 ASSET NEEDS EVALUATION

The Asset Needs Evaluation process is designed to identify and assess the needs underlying the selection and grouping of potential candidate investments and facilitate risk assessment and calibration.

The needs assessment process identifies:

(i) asset needs based on condition and performance data;
(ii) customer needs and preferences;
(iii) system needs (including regional planning considerations);
(iv) sources of risk that could affect the execution of the work program or achievement of targeted outcomes; and
(v) other external influences.

HOSSM performs the asset needs evaluation using the available system information, such as asset condition scores, equipment performance trends, and other factors described in more detail below. This process is known as the Asset Risk Assessment ("ARA"). The result of the ARA is an initial portfolio of projects and programs to be considered in the next step of the asset management process.

Asset Risk Assessment

The ARA process integrates asset condition and performance data, engineering analysis and other information to identify individual assets and subsections of asset population that require some form of intervention over the plan period. The ARA primarily targets the major equipment groups, namely transformers, conductors, breakers, and protection and control systems.

When examining Hydro One's assets, the ARA process includes an assessment using an integrated quantitative multi-factor Asset Analytics platform, which evaluates information drawn in real time from multiple Hydro One databases to identify the areas warranting further attention from planners. Given that the integration of HOSSM's asset management data with Hydro One's system is ongoing, planners relied on a modified version of the ARA process, reflective of its key assessment dimensions and available HOSSM system data. The ARA process evaluated system needs on the basis of the following five[6] risk factors:

- Condition - Risk related to the increased probability of failure that assets experience when their condition degrades over time. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently. Assets determined to have a comparatively high condition risk become candidates for intervention.
- Demographics - Risk related to the increased probability of failure exhibited by assets of a particular make, manufacturer, or vintage. Typically, the probability of asset failure increases with age. In certain cases, assets of a particular make or year of manufacturing exhibit known performance issues, making them candidates for replacement, refurbishment or other form of intervention.

---

[6] Hydro One's ARA process includes a sixth evaluation dimension – "Economics", which examines the historical costs of reactive interventions for a specific asset against a threshold reference value developed on the basis of historical information. In the absence of requisite HOSSM data to perform this analysis, it was not completed for the purposes of the HOSSM TSP preparation.

- Criticality - Represents the impact that the failure of a specific asset would have on the transmission system, based on that asset's electrical location, the amount of load it supports, and the extent of available system redundancies. Criticality is a criterion that the analysis employs to further prioritize among assets identified as potential investment candidates on the basis of other assessment factors.
- Performance - Risk that reflects the historical performance of an asset, as represented by the frequency and duration of past outages. Assets with a known history of material outages represent viable candidates for replacement, refurbishment or additional follow-up.
- Utilization - Risk associated with accelerated rate of deterioration experienced by assets that are consistently utilized at levels approaching or exceeding their normal operating capacity. The asset utilization risk for assets like transformers and circuit breakers attempts to consider their relative deterioration based on available loading and operational history, respectively.

HOSSM planners take into account a range of other considerations and data sources, as informed by sound engineering oversight and experience-based decision making. Local knowledge regarding the frequency, manifestation and impact of issues of the HOSSM system was of particular importance in the development of the current TSP.

The outputs of the ARA process are potential candidate investments that are put forth for further consideration during the IPP process. The ARA work establishes the necessary evidentiary fact base used by planners to assign the probability and consequence of reliability, safety and environmental issues that candidate investments seek to mitigate. The assessment of risk mitigation potential occurs in the course of the subsequent stage of the HOSSM asset management process – Investment Planning.

Also included in HOSSM's Asset Needs Evaluation process is the assessment of Customer Needs gathered through Customer Engagement activities, the System Needs Assessment, and the consideration of External and Other Influences. Each sub-component is described in the pages that follow.

Customer Needs Identification

Talking with customers regarding their existing and evolving needs and their perspectives on the strategic and operational steps contemplated by HOSSM is at the core of its operating practices. HOSSM receives customer feedback on a regular basis through a variety of channels. In general, HOSSM views customer needs as consisting of two components – initial connection needs and needs of existing connected customers.

HOSSM identifies initial customer connection needs by way of connection applications received and reviewed through its Customer Connection Process. HOSSM assesses the needs of existing customers through continuous monitoring of the power system and regular engagement with customers, as well as discussions that take place as a part of the Regional Planning process, as described in Section 2.3.1.

Customer Engagement

HOSSM conducts regular customer engagement meetings with its transmission-connected customers. In the course of the meetings, parties review HOSSM's performance across the interconnection points between the customer and HOSSM's assets, evaluating them against the applicable OEB standards, and exploring the drivers of each outage, as well as potential means of mitigation of recurrence in the future.

HOSSM and customer representatives also discuss capital and maintenance plans over the near-term horizon to ensure that final scheduling and work execution reflects both parties' needs and expectations. HOSSM also presents customers with information regarding its capital project plans over the forthcoming five years to hear customer input for future incorporation into the plans. For example, one such project incorporated into HOSSM's TSP as a result of recent discussions with customers is the procurement and installation of a spare power transformer to be located at the Echo River TS, to supplement the single transformer currently deployed at that location for use in contingency situations (see ISD #SA-01 for further details).

As HOSSM's operational alignment with Hydro One moves forward, HOSSM customers will continue to be engaged to voice their needs and preferences. In the most recent round of customer engagement work conducted in late May of 2018, staff from both Hydro One and HOSSM attended all customer meetings. Discussions covered the following topics:

- the anticipated pace of the Hydro One and HOSSM integration;
- benefits of the recently consolidated control centre operations;
- additional channels of communication enabled by integration; and
- soliciting ongoing customer feedback on needs and preferences.

Consistent with findings from Hydro One's engagements with its existing customer base, the customer engagement sessions with HOSSM customers confirmed that predictability and pacing of investments to maintain gradual and uniform impact on rates was a key preference of customers. Specific customer priorities showcase a degree of variability depending on the type of customers. Whereas industrial customers are primarily concerned with power quality and keeping the outage frequency low, HOSSM's two Local Distribution Companies' ("LDCs") customers placed more emphasis on avoidance of lengthy outages.

As discussed in Chapter 4, HOSSM's 2018-2026 capital plan is aligned with the priorities expressed by HOSSM customers. For example, the Echo River TS Spare Transformer Installation responds to a customer request to enhance contingency capabilities at what is currently a station equipped with a single transformer with a history of outages. The reconductoring and replacement of structures on the Sault #3 Line (ISD# SR-02) seeks to improve performance of the circuit with the most outages in the recent years.

System Needs

Distinct from Asset Needs identification work, the System Needs process includes work necessary to ensure that the transmission system as a whole is maintained and operated to provide the level of service expected by customers. System needs are driven by the requirement to meet current and forecasted load demand, including provision of the following:

- Adequate transmission capacity to reliably deliver electricity to the local areas connected to HOSSM's transmission system;
- Inter-area network transfer capability to enable electricity delivery from areas with sources of supply to load centers across the system;
- Protection and control modifications to Hydro One's transmission stations to address the impacts of distribution-connected generation;
- Mitigation measures to minimize high-impact risk (e.g., installing special protection systems to protect equipment from overload conditions) and ensure the safe, secure and reliable operation of HOSSM's transmission system in accordance with the Market Rules, TSC and other mandatory industry standards such as those established by the North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC"); and
- Power quality data collection capabilities and pilot cost effective mitigation measures to address specific issues faced by customers.

Under the electricity industry structure in Ontario, the need for new transmission system facilities or system enhancements may be identified by a Licenced Transmitter, the IESO, the Government of Ontario (e.g. through the Long-Term Energy Plan), or customers. These needs are identified and assessed in conjunction with customers, the IESO and LDCs under the regional planning process as outlined in Section 2.3.1.

External and Other Influences

In developing and executing its capital plans, HOSSM monitors the evolution of technical standards and operational best practices identified through staff research or provided by external consultants. Examples of initiatives where industry best practices research informed the elements of HOSSM's asset management strategy include the report by One Line Engineering on the state of HOSSM's relay population (See Appendix E), and conductor remaining strength testing by Kinectrics (See Appendix C) that confirmed the poor condition of the Sault #3 Line, scheduled for reconductoring over the Plan period.

As discussed in Section 3.1, the integration of the two entities' respective asset management functions is in the early stages. However, as this integration proceeds, HOSSM will gradually transition to the planning, work execution and technical equipment standards used by Hydro One.

3.1.3.3 INVESTMENT PLANNING

Based on the asset needs identified through the ARA process, HOSSM planners identify a set of candidate investments that undergo further evaluation as a part of the IPP. To become a candidate for consideration, a proposed investment must address a distinct need, incorporate the applicable planning assumptions, and be grounded in evaluation of objective and verifiable information.

Proposed investments are classified into one of the four OEB investment categories: System Access, System Service, System Renewal, and General Plant. HOSSM used the ARA process primarily to identify the System Renewal and System Service investments. Other processes are used to identify System Access and General Plant asset needs.

System Renewal

System Renewal investments aim to extend the expected service life of transmission assets through replacement or refurbishment to minimize the life cycle costs and maintain reliability performance.

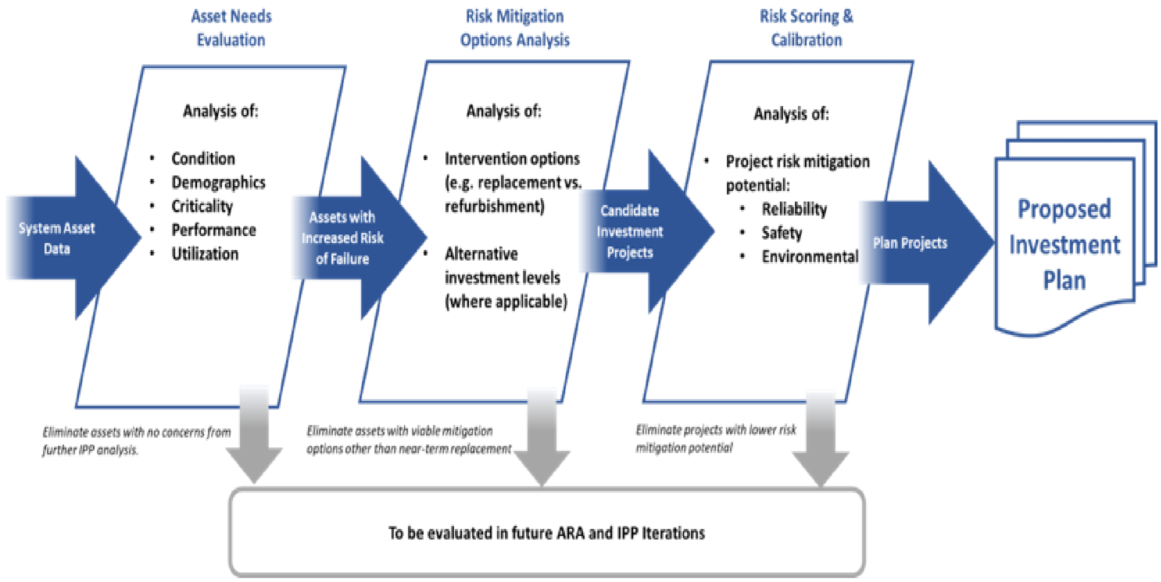


Figure 3-3: System Renewal Project Investment Planning Process

In general, identifying and selecting System Renewal investments involve several steps. The first step is to consolidate the asset needs in the ARA by major asset type. The next step is to identify options to mitigate risk for assets that are deemed to have a significant increased risk of failure. For program work, alternative levels of investment and their corresponding level of risk are defined and evaluated against the status quo and the preferred option. Finally, the "Scoring and Calibration" step of the Investment Planning process identifies the preferred solution that becomes a part of the Plan. Figure 3-3 provides a graphical representation of this process.

System Access

System Access investments are non-discretionary investments driven by mandated service obligations to connect customers in accordance with HOSM's Transmission Licence. They include provision of new or modified existing customer connections. System Access investments include either load customer connections or generator customer connections.

Load Connection investments are initiated based on customers' requirements for capacity and reliability improvements or identified by the Regional Planning process discussed in Section

2.3.1. The investments may cover provision for new or modified transformation connection facilities, new feeder positions at existing transformer stations, or construction of new connection lines and stations.

Generation connection investments are typically addressed through radial connection facilities, unless other modifications (e.g. protection system upgrades, reactive power support, etc.) are needed to ensure integration of the facilities without compromising reliability for the existing customers. The costs incurred in the process of connecting generation and load customers are typically recovered in full from the benefitting parties according to the pertinent rules in the TSC.

In the case of the present TSP, HOSSM is planning only one System Access investment, namely the Echo River TS Spare Transformer Installation. The need for this process was identified among the three “wires-only” solutions in the 2014 Regional Planning process, and subsequent customer engagement activities.

System Service

System Service investments represent potential modifications to maintain and enhance operational stability, reliability and efficiency of the HOSSM transmission system due to evolving load requirements and anticipated capacity constraints, inter-area transfer capability needs, and operational objectives such as local area supply adequacy, operation of equipment within the ratings, and operating flexibility. For the purposes of this Plan, HOSSM also included upgrades and replacements to Protection Relays among the System Service investments, as planned replacements are driven by technological obsolescence of specific units, or the need to upgrade station protection infrastructure to maintain interoperability with the remainder of the system.

Investment candidates in the System Service portfolio were identified through the Asset Needs review component of the ARA process, incorporation of recommendations from the studies performed by external consultants, and the review of the current configuration of HOSSM's station design to identify opportunities for potential modifications to improve their operating efficiency. The candidate projects subsequently underwent assessment through the "Scoring and Calibration" step of the Investment Planning process to select the preferred projects.

General Plant

General Plant investments are comprised of modifications or replacements to assets that are not directly or specifically part of the transmission system. These may include investments related to transport and work equipment fleet, facilities, and information technology. The identification and prioritization among the potential General Plant investments is grounded in discrete processes conducted within the relevant functional areas, which involve:

- Identification and confirmation of need (e.g. maintaining of operational health and safety standards, continued support of work execution requirements, mitigation of identified risks, work process improvement opportunities, etc.);
- Development and review of available alternatives to address the need, including such things as financial implications, impact on staffing requirements, operations of the utility as a whole, comparison with industry best practices, review of manufacturer standards; and
- Selection and execution of the preferred alternative.

At this stage of candidate investment development, once it has been determined that a proposed investment meets a relevant need, planners prepare a high-level scope and preliminary estimate of cost and schedule so it can be considered for inclusion in the investment plan.

3.1.3.4 SCORING AND CALIBRATION

The Scoring and Calibration stage of Hydro One's IPP used in preparation of HOSSM's TSP involves estimating the potential risk mitigation impact across the candidate investments and "calibrating" the risk scores for consistent application across the investment types and projects.

Hydro One's scoring process was applied to the HOSSM plan and reflects a number of enhancements since it was last presented to the OEB in EB-2017-0049. Enhancements include a clearer and more intuitive scoring framework, the use of "flags" to denote important aspects of particular projects, and a more standardized calibration process. The risk scoring system consists of three discrete risk taxonomies – each with its own scale for quantifying the probability and consequence of events. The three risk taxonomies, or variables representing different dimensions of risk, are Safety, Reliability and Environment.

Underlying the scoring and calibration taxonomy for all three categories is a simple definition of risk, expressed as the following formula:

$$Event\ Risk = Event\ Probability \times Event\ Consequence$$

Consistent with the above formula, the goal of the Investment Scoring and Calibration process is to determine appropriate scores for the probability and consequence of events that each candidate investment seeks to mitigate, and subsequently determine how much of the total risk each proposed investment can be expected to mitigate. Since no investment can be expected to completely eliminate any risk, a portion, known as residual risk will always remain. Once properly scored and calibrated, investment candidates are then assessed on the basis of how much initial risk they are expected to eliminate. The results of this assessment provide HOSSM with a quantitative basis on which to prioritize the candidate investments across various portfolios.

Each risk taxonomy is fact-based, reflecting either Hydro One's own experience or comparable industry data. For example, different levels of safety consequence are based on historical data of safety outcomes derived from utility industry experience. Reliability consequence information is based on realistic customer outcomes for escalating levels of consequence based on data from

Hydro One's system. Importantly, the three taxonomies (Reliability, Safety and the Environment) are closely aligned with the OEB's Renewed Regulatory Framework ("RRF") outcomes and also reflect the priorities identified by the results of Customer Engagement activities.

HOSSM notes that despite its comparatively smaller scale, the analysis of its proposed investment candidate did not incorporate adjustments to the respective taxonomy scales, given the relative recent implementation of Hydro One's new methodology and the expectation that over the coming years the HOSSM system will be evaluated as a regular part of the Hydro One system. While certain consequence categories (such as outage consequences at the upper end of the Reliability scale) cannot apply to HOSSM given its relatively small size, keeping the taxonomy consistent from the outset of this methodology being applied to the HOSSM assets will simplify the scoring process in the subsequent iterations of the Plan.

The scoring process consists of the following six steps:

1. **Understand an investment's primary purpose:** Identify an investment's primary objective and the applicable risks taxonomies (safety, reliability or environmental).
2. **Define Worst Reasonable Direct Impact ("WRDI"):** Identify the worst reasonable direct outcome of not making the investment and, if available, the costs associated with such an event occurring.
3. **Determine the consequence of the baseline risk:** Establish the consequence of the WRDI using the updated risk-based framework.
4. **Determine the probability of the WRDI event:** If no investment occurs, evaluate the probability of the WRDI occurring using the new risk-based framework.
5. **Determine the residual consequence and probability:** Determine the consequence and probability of the WRDI occurring even if the investment is made.

6. **Calculate the final mitigated risk score:** Determine the final mitigated risk score based on the difference in baseline and residual risk score for each of the three applicable risk areas (safety, reliability, and environment).

A key parameter of this process is the WRDI, which is what a reasonably undesirable outcome might be as a direct result of not making a particular investment (e.g., failure event that is the most reasonable, additional cost/risk of repair during emergency compared to regular operation). Of note is the fact that the framework does not call for the worst possible outcome, but rather for one that can be reasonably expected to occur, and cause material damage. The “reasonableness,” as related to each investment, is a function of planners’ expectations in light of (i) historical events, (ii) unique characteristics of proposed investments, and (iii) confidence in the outcome occurring. The “directness,” on the other hand, is an assessment of whether the event/damage is an immediate result of the failure itself, or a secondary result.

Each of the three risk taxonomies has seven consequence levels upon which each investment is scored. The seven consequence levels are based on the financial impact of a given anticipated WRDI and are quantified to the same scale for each of the three risk taxonomies. Each risk taxonomy features clear definitions and consistent scoring, which permits a consistent comparison between candidate investments.

The scores are calibrated to be comparable across taxonomies, so that a score of “6” in the reliability consequence taxonomy is comparable to a score of “6” in safety and environmental taxonomies in terms of the negative outcome experienced by the utility, its customers and/or general public as a result of the event.

For safety, the impact on both the workforce (employees and contractors) and the public may be considered, in which case the higher score of the two is used in evaluation.

For reliability risks, five metrics are considered (number and significance of customers, load loss, unsupplied energy, and outage duration), which capture the impact to HOSSM's customers from interruptions. Figures 3-4 through 3-6 illustrate the risk taxonomies.

Taxonomy to evaluate consequences related to one failure event

Score	Impact on workforce : employee and contractor[1]	OR	Impact on public
7	▪ Multiple fatalities of employees		▪ Multiple public fatalities
6	▪ Fatality to 1 employee		▪ Fatality to a single member of public
5	▪ Permanent health consequence that precludes injured party from regular day-to-day activity (e.g., paralysis)		▪ Permanent health consequence that precludes or hinders injured party from regular day-to-day activity
4	▪ Permanent health consequence that hinders the injured party from regular day-to-day activity / doing their job (e.g., loss of hand)		▪ Permanent health consequence that does not prevent injured party from most regular day to day activity ▪ Injury to member of public requiring extended medical treatment with more than 8 weeks recovery time
3	▪ Permanent health consequence that does not prevent injured party from most regular day to day activity, e.g. doing their job (loss of finger) ▪ Injury requiring medical treatment resulting in 8+ weeks absence or temporary modified work for the employee		▪ Injury or illness to member of public requiring medical treatment with less than 8 weeks recovery time ▪ No permanent health consequences
2	▪ Injury requiring medical treatment resulting in less than 8 week absence and no modified work for the employee ▪ No permanent health consequences		▪ Minor injury to member of public requiring First Aid with quick and complete recovery in less than 1 week; No permanent health consequences
1	▪ Minor injury requiring First Aid resulting in less than a week absence and no modified work for the employee ▪ Quick and complete recovery without permanent health consequences		▪ No impact on public

Figure 3-4 – Safety Consequence Framework

Taxonomy to evaluate consequences related to one failure event

Score	Impact on customers	OR	Load impacted	OR	Unsupplied energy	OR	Outage Duration
7	Impacts an entire metropolitan area, including multiple customers **and** 2+ priority customers		>500 MW		>1 200 MWh		> 7 days
6	(Impacts on at least 3 customers **and** one priority customer) **or** Impact on 2+ priority customers		200-500 MW		500 -1 200 MWh		1-7 days
5	Impacts on at least 3 customers **or** including multiple critical locations **or** one priority customer		75-200 MW		200 – 500 MWh		10-24 hours
4	Impacts on at least 2 customers **or** including a single critical location		25-75 MW		25 – 200 MWh		1-10 hours
3	Impacts one customer resulting in a small area outage with no disruption of service to critical locations (e.g., water plan)		<25MW		<25 MWh		<1 hour
2	No power interruption		None		None		None
1	No power interruption and no supply through redundancy		None		None		None

Figure 3-5 – Reliability Consequence Framework

Taxonomy to evaluate consequences related to one failure event

Score	Description[1]	Examples[2]
7	▪ **Catastrophic / irreversible changes to the environment** such as entire loss of habitat, plant, and/or animal populations/ species at risk in the impacted area; will never completely recover ▪ Chronic threat to human health; National media coverage, viral social media coverage/criminal charges/ major fines/charges	Catastrophic/negligent release of PCB oil to sensitive environmental area requiring significant remediation, engineering, and/or long-term monitoring
6	▪ **Significant change to the environment** – substantial loss of habit, plant and/or animal populations / species at risk in the impacted area; requires multiple years to recover completely; Chronic risk to human health; ▪ Widespread provincial media coverage; significant fines/charges/order to comply	Very large off-site soil and/or groundwater contamination due to historical practices; significant release of PCB oil to a sensitive environmental area requiring significant remediation, engineering and/or long-term planning; catastrophic SF6 release
5	▪ **Notable change to environment** – visible loss of habitat, plant and/or animal populations / species at risk in impacted area; requires 1-2 years to recover completely ▪ Definite acute risk to human health ▪ Provincial media coverage; fines/order to comply	Large off-site soil and/or groundwater contamination due historical practices; notable PCB oil to sensitive environmental area requiring significant remediation, engineering and/or long term planning; some SF6 release
4	▪ **Measurable change to environment** – moderate loss of plant and/or animal populations/species at risk in impacted area; damage to environmentally sensitive sites/special interest sites; requires months/year to recover completely ▪ Potential for acute risk to human health ▪ Widespread local media coverage; limited fines/order to comply	Moderate on/off-site soil and/or groundwater contamination due to historical practices; measurable PCB oil, mineral oil, hydraulic oil or other hazardous liquid spill to an environmentally sensitive area requiring moderate remediation, engineering, and/or long-term planning
3	▪ **Limited change to environment** – limited loss of habitat, plant and/or animal populations/species at risk; requires weeks/months to completely recover ▪ Potential for limited risk to human health ▪ Local media coverage; inspection/ comment from regulator/order to comply but no charges/fines	PCB regulatory infraction/fine; minor on/off-site contamination from historical practices; large spill/fire of PCB oil, mineral oil, hydraulic oil or other hazardous liquid requiring remediation, engineering, and/or long-term monitoring
2	▪ **Limited change to environment/ requires day(s) to recover completely** ▪ No plant and/or animal species impacted ▪ No acute risk to human health ▪ No media coverage; minor regulatory fine or order	Large spill/fire of PCB oil or mineral oil requiring cleanup; other large volume liquid spills requiring cleanup (i.e., hydraulic oil, coolant); SAR infraction/fine; invasive species infraction/fine
1	▪ **Limited change to environment/ recovers immediately after remedial action** ▪ No media coverage; no regulatory fine or order	Typical pole-top/ padmount transformer spill of PCB oil or mineral oil requiring cleanup; other liquid spills requiring clean up (i.e., hydraulic oil, coolant) Minor liquid spills (mineral oil, hydraulic coil, coolant); minor environmental incidents (e.g., wood pole treatment seepage)

Figure 3-6 – Environmental Consequence Framework

The probability scoring (set out below in Figure 3-7) is an assessment of the likelihood of a failure event happening in a given year or any associated period of time based on the WRDI defined for the associated consequence. The probability framework applies to all three taxonomies and has been informed by customer feedback.

For instance, HOSSM equated the incidence of four or more failures per year to the highest level of "7" based on HOSSM customers' feedback, indicating that frequent outages were highly disruptive to their operations. Investments are scored on each framework according to the metric with the maximum score.

Taxonomy to evaluate the probability of a failure event

Score	Frequency OR	Expected time to event OR	Prob. of event occurring in the next yr. OR	Prob. of event occurring in the next 5 yr.	Example phrases you might hear during scoring
7	4+ per year	<3 months	100%	100%	This has happened 10 times every year for the last 5 years
6	1-4 times per year	3-12 months	100%	100%	Based on run time, the equipment life is over for 2 years, it will fail in the next year
5	1 every 1-3 years	1-3 years	33-100%	85-100%	We have to trench every 2 years, disturbing the habitat
4	1 every 3-10 years	3-10 years	10-33%	40-85%	We see this event about once a year on the whole system, which has 8 of these assets
3	1 every 10-25 years	10-25 years	4-10%	20-40%	This event happens on the system sometimes, and it's much more likely to happen here
2	1 every 25-100 years	25-100 years	1-4%	5-20%	This would happen on an APD (abnormal peak day), a 1/90 year event
1	Less than 1 every 100 years	>100 years	0-1%	0-5%	This has never happened, and I don't want to think about how we'd let it happen

Figure 3-7 – Probability Framework

Although not every single consideration involved in the scoring process can be 100% objective and decoupled from personal judgment, it is important to recognize the significance and value of the process enhancements made to emphasize fact-based and quantitative decision-making to the extent possible. If available, data is always used for purposes of making and justifying a particular scoring decision.

Flagging

As part of its improved scoring process, Hydro One has introduced a new "flagging" process that has also been applied in the context of the HOSSM TSP preparation to account for special considerations and ensure stakeholder perspectives are consistently included in evaluating investments. Investment considerations that cannot be quantified using the risk frameworks are captured by using qualitative flags, which allow consideration of potential benefits of an investment beyond risk mitigation. To incorporate key customer and regulatory outcomes into its evaluation of projects, the flagging system enables planners to identify investments that address key customer priorities such as improving power quality and address investments that align to strategic priorities, which include environmental and broader public policy considerations.

Flags are classified as either "mandatory" or "non-mandatory." Flagging is guided by specific and discrete categories which are common and consistent across proposed investments. As risk scoring cannot always capture all relevant considerations, flags are applied to investments when such other considerations are deemed to be material drivers of the funding decision.

The following flags have been established to provide a clear guidance and a more rigorous definition of what constitutes a *mandatory* investment:

- **Immediate / Short-term Compliance** - Explicit obligation to a regulatory agency (e.g. OEB requires work to be done within a year with immediate risk of legal or regulatory non-compliance);
- **Third party requests** - Explicit connection request by a city, county, agency, or customer, with a one to five-year risk of breaking the utility obligation to serve;
- **Contractual** – Signed, fixed-sum contracts with third parties for services such as IT support, facility support, etc.; and
- **In-Flight** – Project already under construction.

The following flags are used for *non-mandatory* investments and represent factors that are important to Hydro One and its customers:

- **Customer Engagement** - Influence of customer engagement feedback; response to specific customer needs and preferences;
- **Productivity** - Contains committed productivity savings, as tracked by the corporation, or facilitates future productivity savings;
- **Corrective Maintenance/Demand Replacements** - A risk identified by Hydro One or other utilities that requires near-term action (e.g. break/fix);
- **Preventative Maintenance/System Renewal** - Opportunity to prolong asset life with planned and condition-based maintenance;
- **Strategic** - Explicit request to advance a strategic objective; and

- **Political Commitments** - Explicit statement by a Hydro One officer to non-agency parties such as politicians, media or through official public statement, etc.

The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization of investments to ensure consistent comparison and prioritization between investments across lines of business. The conversion is completed using a risk matrix, as presented in Figure 3-8 below, and total risk mitigated is calculated by summing the risk score for each of the three taxonomies - safety, reliability and environmental. In order to more effectively differentiate between the risk levels of investments with similar consequence and probability scores, a logarithmic scale is used to assign risk scoring points.

Risk score (risk unit)

Consequence							
7	900	4,200	12,000	36,000	100,000	400,000	1,000,000
6	430	1,900	5,000	17,000	50,000	200,000	500,000
5	170	800	2,100	7,000	20,000	80,000	200,000
4	60	280	800	2,400	7,000	28,000	70,000
3	20	80	230	700	2,200	8,000	20,000
2	4	20	50	150	460	1,700	4,200
1	1	3	10	30	90	350	800
	1	2	3	4	5	6	7
	Probability						

Figure 3-8: Hydro One Risk Matrix Applied to HOSSM Projects

A broad range of representatives convene to review the resulting portfolio from a variety of perspectives, stress-test the assumptions and rankings, and evaluate the trade-offs between similarly ranked investments.

Challenge Sessions

Challenge sessions are designed to provide a structured approach to stress-test the investments comprising the planned portfolio, ensuring that the right investments are included in the Plan. The discussions allow for the merits of an investment and its resultant benefits to be considered from both risk and non-risk perspectives. Various levels and types of stakeholders attend, incorporating execution feasibility and strategic alignment considerations.

As part of the challenge sessions, trade-off decisions assess which investments should be promoted or demoted based on such parameters as:

- The planners' level of comfort with the risk that remains unmitigated after the investment portfolio is assembled; and
- The investments selected on the basis of non-risk considerations (e.g. by use of qualitative flags) relative to risk-based investments outside of the Plan portfolio.

At the completion of the Challenge Sessions, staff record the changes made to the investment portfolio, along with the rationales that support these changes and the impact on the contemplated investment portfolio driven by these changes.

3.1.3.5 CAPITAL WORK EXECUTION

The final stage of HOSSM's Asset Management Process entails the execution of the investments included in the TSP. The Plan is reviewed throughout the execution phase as new information on asset condition and risks becomes available. At present, HOSSM's capital work program is largely performed by outside contractors. HOSSM expects this to remain the case for the early stages of its integrated operations with Hydro One. The decisions as to the scope, nature, and timing of any changes to the work execution processes and standards will be made in accordance with the asset management function's phased integration process laid out in Section 3.1.

As changes to investment needs or other emerging priority circumstances occur during the Plan period, HOSSM may reprioritize the investments by changing the planned timing, sequencing or the scope of projects contemplated for delivery within a given a year. In the initial years of integrated operations, the decisions as to potential changes to the work program will be made by HOSSM planning staff in consultations with Hydro One counterparts. Should the contemplated changes affect any HOSSM customers, planned Hydro One work in the area, or the inter-area transfer capability of the IESO-controlled grid, the utility will notify and consult with affected parties as soon as practicable.

As the operational integration between Hydro One and HOSSM moves forward, the decisions regarding the potential changes to HOSSM's investment portfolio will become subject to the review of Hydro One's recently formed Redirection Committee, tasked with overseeing the redirection process wherein investment changes are approved, documented, systemized and communicated to the relevant stakeholders, to ensure an enterprise-wide understanding regarding issues affecting the execution of HOSSM's investment plan.

Throughout the execution of its planned capital work program, HOSSM will track the progress of its accomplishments, to enable assessment of the extent to which the targeted outcomes have been achieved and risks have been mitigated, assess the variances between the planned and actual project costs, and evaluate any other insights that emerge in the process of work execution.

3.2 OVERVIEW OF ASSETS MANAGED

The asset management process described in the preceding section ensures that HOSSM's transmission system operates safely, reliably and in accordance with the applicable technical standards, customer preferences, and the relevant statutory and regulatory requirements. This section of the TSP provides a detailed description of the utility's asset base and system configuration.

3.2.1 HOSSM ASSETS AND SYSTEM CONFIGURATION

The assets comprising HOSSM's transmission system are located in the area characterized by dense vegetation, steep changes in elevation and rugged terrain; characteristic of the Canadian Shield. HOSSM equipment traverses two forest zones – the Great Lakes-St. Lawrence zone in the south and the Boreal forest zone in the north. Both forest zones have dense and mature growths that pose operating challenges, particularly in the context of vegetation management and storm restoration activities.

Low population density (2.3 resident per square km vs. the Ontario average of 14.8)[7], rugged terrain and sparse civil infrastructure in some parts of the HOSSM territory have a material impact on the utility's capital and operating costs. Depending on the area of the system, project costs may be materially higher due to the transportation, equipment access, materials staging and safety requirements, among other cost drivers. While HOSSM expects that many of these issues will be positively affected by the integration with Hydro One, the terrain, vegetation, and physical distance from the operating centres will remain among notable cost drivers going forward.

---

[7] Statistics Canada, 2016 Census Profile, Algoma Region, accessed at http://www12.statcan.gc.ca/census-recensement/2016/as-sa/fogs-spg/Facts-cd-eng.cfm?LANG=Eng&GK=CD&GC=3557&TOPIC=1 on June 20, 2018

Table 3-2 provides the average annual weather data for HOSSM's service territory, as represented by Sault Ste. Marie, ON, along with corresponding information for Toronto, ON, provided for comparative purposes.[8]

Table 3-2 HOSSM Service Territory Comparative Weather Data

Category	Sault Ste. Marie, ON	Toronto, ON
Average Monthly Temperature (°C)	4.3	9.2
Average Annual Rainfall (mm)	634	709
Average Annual Snowfall (cm)	302	133
Average Days with Precipitation per Month	10	12
Average Wind Speed (km/h)	12	33
Average Days with Freezing Rain / Year	12	2
Average Days with Thunderstorms / Year	12	17
Average Monthly Snow Depth (cm)	10	1.4

As the preceding table indicates, HOSSM's service territory receives a considerable amount of snowfall during the winter months, materially complicating equipment access for a portion of the year, including creating safety clearance issues for crews undertaking planned or reactive maintenance work on certain station assets. While wind speeds are comparatively low throughout the year, HOSSM's lines are exposed to an average of 12 days a year with freezing rain or drizzle.

Overall, the length and severity of the winter season weather represents the most significant climatic drivers affecting the HOSSM operations, affecting the length of the construction season,

[8] The Weather Network, https://www.theweathernetwork.com/forecasts/statistics/precipitation/cl6057592/caon0603 Data represents rolling average to date based on Environment Canada weather station records. Accessed June 12 2018.

the response and rectification timelines to outage events, and even the types of vehicles in the utility's small fleet which includes snowmobiles.

System Configuration and Power Flows

HOSSM's transmission system consists of the following components:

- 318 circuit km of 230 kV line and associated equipment;
- 232 circuit km of 115 kV line and associated equipment; and
- 11 circuit km of 44 kV line and associated equipment which has been deemed by the OEB as serving a transmission function under section 84 of the *Ontario Energy Board Act*, 1998.

The system represents is a critical link in the north western part of the IESO-controlled grid, which extends from the Manitoba border to Sudbury and is referred to in the following passages as the Northwest Transmission System.

The Northwest Transmission System can be divided into three sections:

- Manitoba to Wawa TS;
- Wawa TS to Mississagi TS; and
- Mississagi TS to Algoma TS (Sudbury).

Manitoba to Wawa TS

This section of the Northwest Transmission System is an injection point of generation produced by the mix of hydroelectric and thermal units. The generation in excess of load in the Northwest section, along with any imports from Manitoba, flows predominantly to the east through the Hydro One lines from Thunder Bay (Mackenzie TS, Lakehead TS) to Marathon (Marathon TS) and on to Wawa (Wawa TS) over the East-West Tie ("EWT").

Wawa TS to Mississagi TS

HOSSM's and Hydro One's transmission systems run in parallel between Wawa TS and Mississagi TS. They affect each other's capability, operation and transmission system limits.

HOSSM's transmission system runs 73 km north-south from Wawa TS to MacKay TS, 91 km from MacKay TS to Third Line TS and 76 km east-west from Third Line TS to Mississagi TS. The HOSSM system in this segment of the Northwest System is comprised of a 230 kV line from Third Line TS to MacKay TS and a 230 kV line from MacKay TS to Wawa TS. There are two 230 kV lines running east-west from Third Line TS to Mississagi TS.

Third Line Transformer Station

Third Line TS is HOSSM's largest station and also serves the largest loads. The station has two switchyards, a 230 kV switchyard and a 115 kV switchyard. As part of the IESO-controlled grid, if either of the 115 kV or the 230 kV sections of Third Line TS were to become unavailable, the reliability and operability of the Ontario bulk power system could be adversely affected. The station is also a connection point that facilitates a parallel with the Hydro One transmission system. Emanating from Third Line TS are three 230 kV circuits and nine 115 kV circuits, which connect various load and generation facilities. The majority of the load directly connected to HOSSM's system is supplied via 115 kV circuits emanating from Third Line TS.

Mississagi TS to Sudbury Section

Mississagi TS is connected to Algoma TS (Sudbury) via Hydro One's 230 kV line and to Hanmer TS (Sudbury) via Hydro One's single 230 kV line. In provincial peak periods, Mississagi TS becomes a point of convergence of power flows from the East-West Tie, the output of generation connected to the HOSSM's system, as well as hydroelectric output of generation in the area connected to the Hydro One system. As a result of the amount of energy deliverable to Mississagi TS through the HOSSM transmission system, the utility's assets are critical for reliable transmission of power from the Northwest Transmission System to southern Ontario.

3.2.2 HOSSM ASSET BASE

Station Assets

HOSSM operates 15 transmission stations, equipped with 20 power transformers, 105 circuit breakers, and a variety of other station ancillary equipment, including switches, shunt reactors and capacitors, protection relays, battery banks, circuit switchers and other ancillary equipment. Figure 3-9 provides an overview of the population size and Health Indices for HOSSM's station assets, as calculated by METSCO in its Asset Condition Assessment report, provided in Appendix B.

Asset Class	Population	Sample Size	Health Index Distribution					Average Health Index
			Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (85 - 100%)	
Power Transformers	20	20	0	0	9	3	8	74.00%
Oil Circuit Breakers	19	19	0	0	0	0	19	90.87%
Vacuum Circuit Breakers	16	16	0	0	0	0	16	93.19%
SF6 Circuit Breakers	70	60	0	0	0	9	51	94.21%
Relays	361	361	13	8	20	118	158	81.84%
Batteries	22	22	0	0	3	6	9	76.14%
Capacitor Banks	2	2	0	0	0	0	2	100%
Reactors	3	3	0	0	2	0	1	78.21%
Circuit Switchers	5	5	0	0	0	0	5	94.77%
Instrument Transformers	59	59	0	0	0	0	59	98.28%
Switches	163	147	2	12	20	43	70	73.92%

Table 3-9 Station Assets Average Health Index

On average, HOSSM's station assets are in a Good to Very Good working condition, however a number of individual assets across classes are in a materially worse condition than indicated by class averages. To further illustrate this point, Figure 3-10 showcases average condition of units in each major asset class grouped by location at each of HOSSM's Transmission Stations. A number of units found to be in Fair condition or worse at locations including Goulais, Batchawana, Echo River, Steelton, are slated for replacement, or other forms of follow-up over the Plan period. In some cases, while Health Indices may indicate an advanced state of deterioration, other intervention activities are considered other than outright replacement as remedial actions may present a more cost-effective alternative in the near term. An example of this are the Clergue TS power transformers, where HOSSM plans to replace the gaskets on transformer bushings, currently characterized by extensive leaks and resulting in the Health Indices approaching the Poor threshold. Performing this refurbishment work is expected to improve the Health Indices for both transformers to the level approaching a Good rating.

Station	Power Transformers	Circuit Breakers	Instrument Transformers	Batteries	Switches	Relays	Circuit Switchers	Capacitor Banks	Reactors	Station Average
Level 1 Stations										
Third Line	71%	96%	100%	72%	92%	89%	-	94%	100%	89%
Mackay	93%	93%	99%	75%	95%	84%	-	-	94%	90%
Anjigami	85%	-	-	-	99%	97%	-	-	-	93%
Level 2 Stations										
Clergue	58%	55%	60%	88%	96%	74%	-	-	-	72%
Gartshore	-	85%	-	75%	75%	85%	-	-	-	80%
Steelton	-	76%	-	75%	98%	82%	-	-	-	83%
Watson	85%	74%	88%	76%	99%	69%	-	-	-	82%
Magpie	-	-	-	100%	97%	87%	-	-	-	95%
Level 3 Stations										
Echo River	56%	62%	75%	100%	-	86%	100%	-	-	80%
Hollingsworth	85%	74%	83%	100%	93%	87%	-	-	-	87%
Northern Ave	73%	86%	85%	50%	99%	74%	-	-	-	78%
Batchawana	69%	-	-	-	-	-	93%	-	-	81%
Goulais	64%	-	-	-	-	-	95%	-	-	80%
Highway 101	-	-	-	88%	-	100%	-	-	-	94%
Andrews	91%	-	-	100%	-	85%	-	-	-	92%

Table 3-10 Average Asset Condition[9] by Asset Class and Station Location[10]

It is important to note that while the METSCO Asset Condition Assessment represents a major step forward for the HOSSM system in terms of producing evidence-based assessments of its equipment, METSCO's Health Index calculations relied on available information previously collected by HOSSM or its contractors. Although the existing information was sufficient to calculate multifactor Health Indices across all the major asset classes, Hydro One uses a number of additional measurements and visual inspection parameters to calculate Health Indices for its own asset base. Over the course of the Plan period, Hydro One and HOSSM will work to

[9] In the majority of cases, blank cells filled by a dash indicate that a particular type of equipment is not installed at a given station, with several exceptions where the asset data is not available. Of note is the fact that while HOSSM refers to all of its stations as "Transmission Stations" four of them are not equipped with transformers, but rather contain a breaker and other ancillary infrastructure.

[10] Levels 1, 2 and 3 in the above table refer to a system criticality framework proposed by METSCO as a reference tool for further system planning activities. See Appendix B, Page 15 for further details.

integrate the collection of additional condition parameters into the course of HOSSM's normal operations.

As the additional condition parameters become available later in the Plan period, HOSSM will transition towards using the Health Index calculation methodology established at Hydro One. Gradual transition to a common Health Index measurement approach and the collection of information to enable it are among the tasks comprising Phases 2 and 3 of the integration process of HOSSM's Asset Management function with those of Hydro One, described in Section 3.1. Detailed description of METSCO's findings on these asset classes along with population demographics are provided in Appendix B, pp. 38-78.

Power Transformers

As shown in Figure 3-11, HOSSM's population of station transformers ranges in terms of its health between Fair and Very Good based on the findings of METSCO's ACA Study.

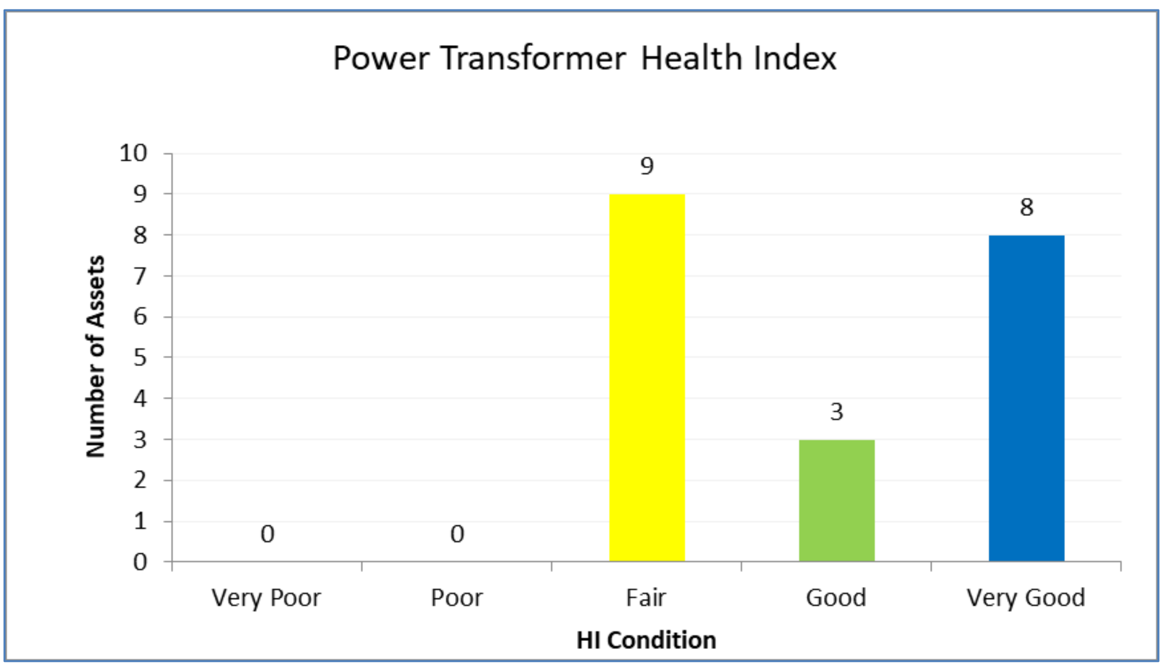


Figure 3-11: Power Transformer Health Index Distribution

As discussed in more detail in the METSCO report (Appendix B), the issues associated with HOSSM power transformers range from deterioration of key physical components such as main tank corrosion, oil leaks and deterioration of civil infrastructure supporting the assets (e.g. concrete foundation/pedestals), to internal deterioration of paper insulation and other components, as supported by the Dissolved Gas Analysis test results.

The demographic distribution of HOSSM's transformer population is directionally correlated with their condition, as showcased in the Figure 3-12, as the older units on average have worse condition parameters, resulting in lower Health Index scores.

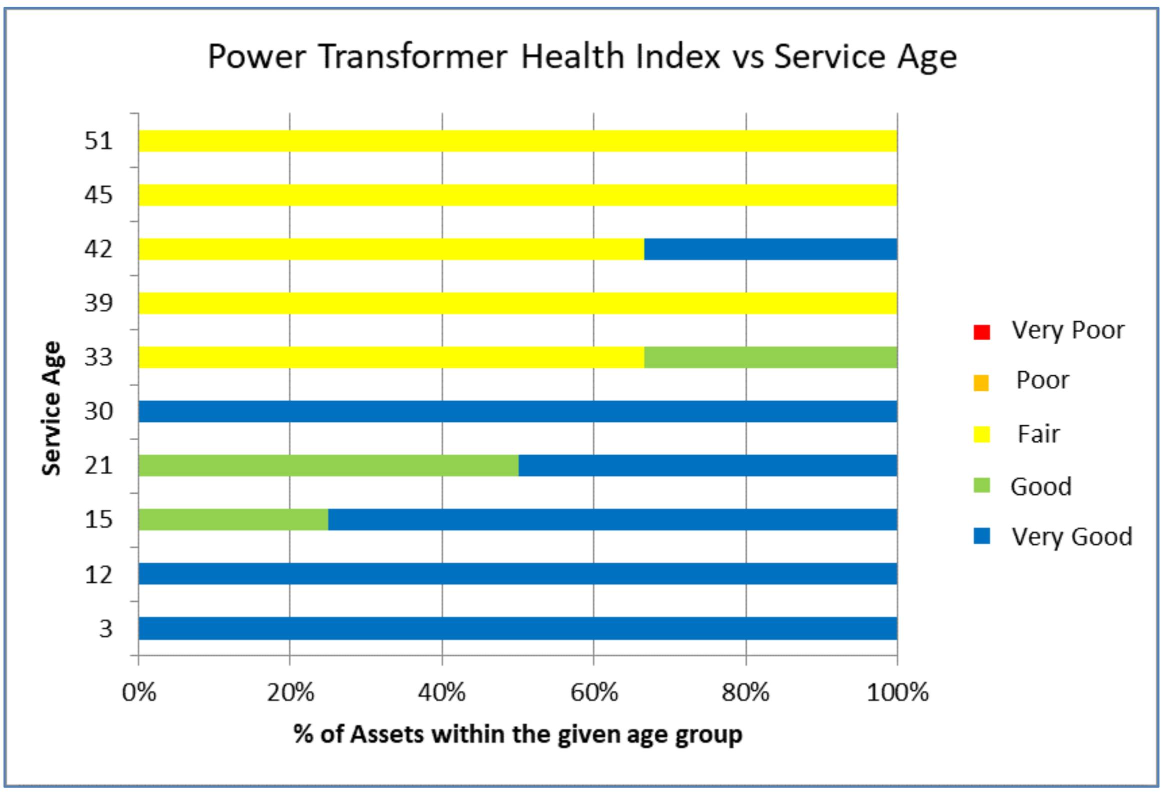


Figure 3-12: Power Transformer Health Index Scores vs. Unit Age

HOSSM's System Renewal work program for the plan period includes replacement of three power transformers in Fair condition, including the oldest transformer in the population (see

Section 4.9 for Investment Summary Documents). Transformer replacements also feature in the System Service investments, where HOSSM plans to convert two existing stations (Goulais TS and Batchawana TS) into a single Greenfield TS station, to enhance the system's operational efficiency, address known safety hazards, and enhance reliability, while replacing two transformers in a deteriorating condition. Yet another project seeks the addition of a spare transformer at Echo River TS, which currently operates on a single contingency basis. The addition of this transformer has been identified in both the customer engagement session with Algoma Power Inc (the local distributor) and in the course of the 2014 Regional Planning exercise, where it was noted as one of the three "wires-only" solutions identified as discussed in more detail in Section 2.3.1.

Circuit Breakers

Among other large station assets, HOSSM deploys 105 circuit breakers across its stations, including oil-filled, vacuum, and SF6 technologies. Figure 3-13 illustrates the breakdown of the breaker condition across all types where condition data is available (90% of the population). Approximately 22% of total breaker population is in Fair condition, which includes all of the Oil Breakers and four SF6-based units.

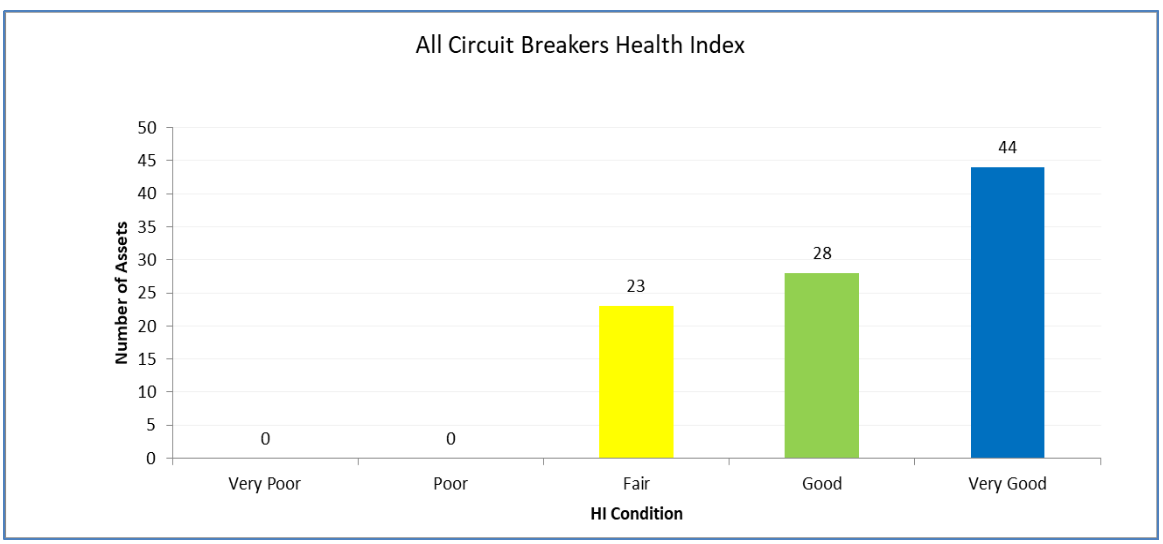


Figure 3-13: HOSSM Breaker Population Health Index

The proposed work program involves the replacement of six circuit breakers, driven by condition, technological obsolescence of the Minimum Oil Breaker technology, and safety clearance issues at certain locations, among others (see ISD SR-07, SS-02).

Protection Equipment

Of all station assets examined in the METSCO ACA study, the population of Protection Relays is the only asset class with units in Very Poor and Poor condition, with approximately 6% of the total Relay Population falling into these categories as shown in figure 3-14.

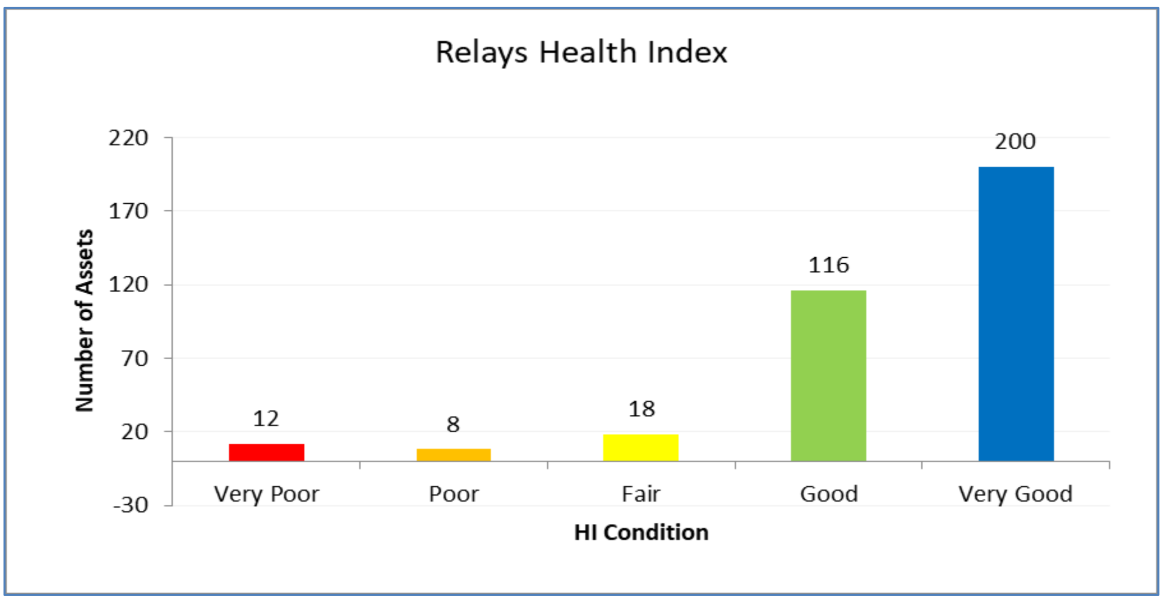


Figure 3-14: HOSSM Relay Population Health Index

According to the METSCO study, a significant portion of the protection relay Health Index scoring is tied to their degree of obsolescence, as determined by ongoing vendor support, parts availability, and ability to support the utility's interoperability needs across the communication devices on their system. As Figure 3-15 indicates, the Relay Health Index distribution is generally correlated with asset age, with the majority of Poor and Very Poor units being among the oldest in the population.

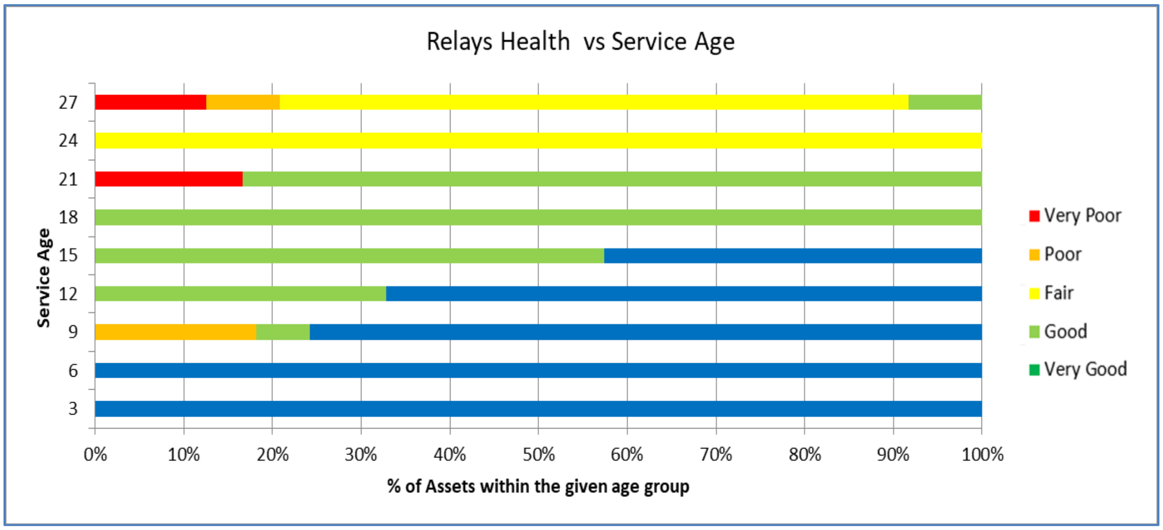


Figure 3-15: HOSSM Relay Health Index vs. Age Distribution

Throughout the 2018-2026 work program, HOSSM plans to replace Protection Relays at three stations that house some of the units in the worst condition as per the METSCO study. HOSSM notes that in opining on the obsolescence of relays comprising the current installed population, METSCO relied on a dedicated study prepared by One Line Engineering, provided in the Appendix E.

Given that determination of obsolescence, both in terms of interoperability issues and continued servicing and deployment of particular types and vintages is a strategic consideration for the operating utility, HOSSM expects that the obsolescence considerations driving replacements in the outer years of the plan may be further updated to align them with Hydro One's relay replacement strategies. In the interim, however, Hydro One and HOSSM have agreed that the latter will proceed with planned replacements on the basis of HOSSM's existing strategy.

Other Station Assets

As can be seen from the figures 3-10 and 3-11, the majority of other station assets are in the Good to Very Good condition across the HOSSM service territory. Detailed descriptions of these assets' condition scores and the parameters utilized to derive them are provided in the METSCO report available as Appendix B to this Plan. A number of smaller individual assets found to be in deteriorating condition (e.g. batteries, switches) are also planned to be replaced as a part of the 2018-2026 capital work program – either as a part of the projects targeting larger nearby assets, or through smaller projects below the materiality threshold.

As operational integration with Hydro One proceeds, HOSSM may identify incremental investment drivers, such as interoperability, corporate technical standards, or broader policy considerations and may modify the scope of currently planned capital work to capitalize on a more economic or otherwise preferable approach.

Line Assets

HOSSM's transmission line assets include conductor, support structures and ancillary equipment such as insulators, cross arms, guy wires, shield wire and grounding equipment.

Conductor

The line assets currently utilize nine different types of conductors depending on voltage, location and vintage of installations. The vast majority of conductor equipment has been in use since the time of the respective lines' original construction. To date, HOSSM maintenance practices have not included regular inspection or testing of conductor condition or performance across the utility's asset base (aside from periodic visual inspections and flyovers) as conductor performance has generally been good.

A notable exception is the conductor on the Sault #3 Line, which is discussed in Section 3.2.3. This line has historically been the worst-performing circuit on the HOSSM system; responsible for 39% of all outage minutes attributable to line equipment failures between 2012 and 2017. For comparison – the second worst-performing line accounts for 12% of total outage minutes over the same timeframe. HOSSM has engaged Kinectrics to test the remaining strength of conductor samples from the Sault #3 Line in the laboratory conditions, which confirmed that the conductor is in poor condition and warrants replacement (See Appendix C for the Kinectrics testing results). While replacing conductor on the circuit, HOSSM will also replace the supporting wood structures which are, in or approaching Poor condition, as indicated by their average Health Index of 55% (See Appendix B, Page 16). Aside from the Sault #3 conductor, HOSSM has seen no persistent issues with conductor performance, and deems the remaining conductor assets to be in Good condition. As HOSSM's integration into Hydro One proceeds, HOSSM will align its practices for conductor inspections and maintenance with those of Hydro One.

Poles and Structures

Conductors are supported by a mix of steel poles or lattice structures, composite fibreglass and wood support structures. Wood support structures represent approximately 86% of all structures, followed by composite installations that make up about 9% of the population, and steel poles and lattice towers that comprise the remaining 5%.

Table 3-3 – HOSSM Support Structure Population

Structure Type	Number of Structures	Percentage of Population
Steel: Lattice	21	1%
Steel: Pole	128	4%
Composite	277	9%
Wood	2,678	86%
Total	**3,104**	**100%**

Wood structures represent the predominant portion of transmission support structures. and include approximately 5,300 individual poles, deployed in single-, two-, three-, or four-pole configurations. Over the last decade, HOSSM, and its predecessor GLPT, have been executing a wood structure replacement program, targeting specific installations with deteriorated condition on the basis of field inspection data.

Figure 3-16: Typical Design of Wood Structures and Observed Types of Damage

The presence of composite fiberglass structures, which currently amount to about 9% of total installations, are the result of a strategic decision made in early 2000s to replace the deteriorated wood structures with composite counterparts going forward. The decision was driven by the objective of extending asset lifecycles in consideration of harsh environmental conditions and extensive woodpecker damage that often compromise the structural integrity of wood poles long before the end of their expected service lives. As with other equipment and material-related decisions, the relative benefits of replacing wood structures with composite ones will undergo review in the ongoing integration efforts with Hydro One, to ensure alignment with the larger utility's sustainment strategy for this asset class.

As shown in figure 3-17, of all support structures for which condition data is available (91% of the population) approximately 3% are in a Very Poor condition, with another 11% in Poor condition. The vast majority (68%) of structures have been found to be in Fair condition as per the results of the METSCO study. All structures found to be in Very Poor and Poor condition are wood structures, while the majority of other structures are in a Good and Very Good condition on the basis of available data.

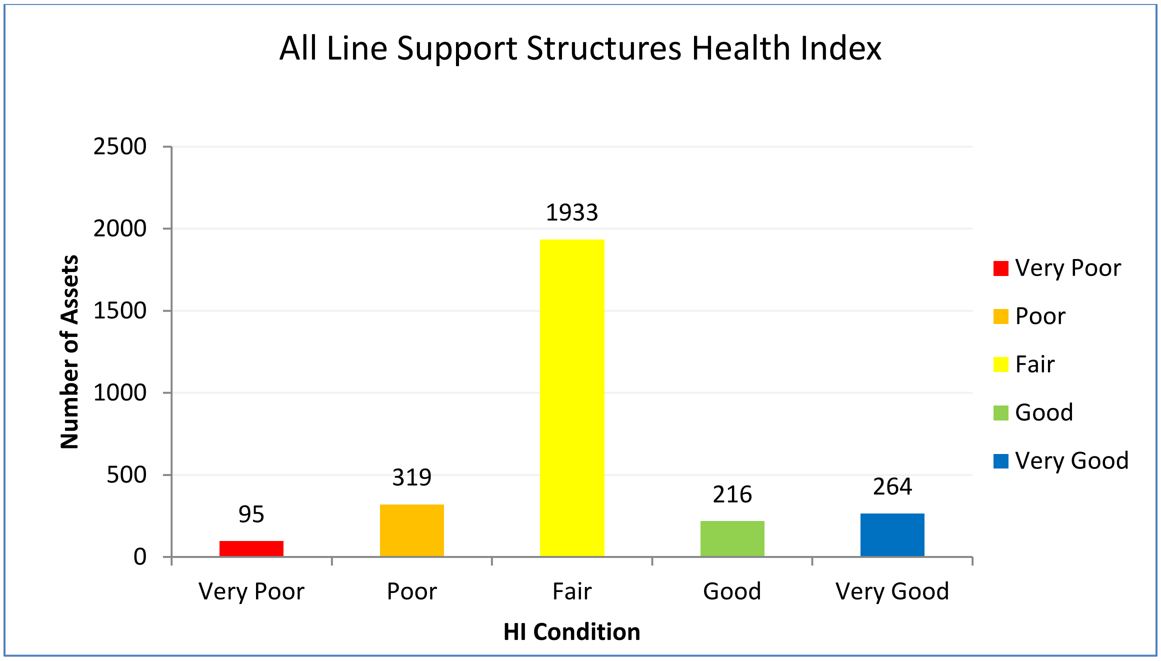


Figure 3-17: HOSSM Structures Health Index

As discussed in more detail in ISDs #SR-01 and #SR-02, HOSSM's planned capital work program includes replacement of between 30-60 deteriorated wood support structures across the utility's circuits per year, as well as a dedicated project to replace conductor in Poor condition and wooden structures on Sault #3 Line transmission line over the Plan period.

An important consideration underlying the cost of support structure replacement work is the remoteness and access difficulties characterizing certain lines with support structures in deteriorated condition. Based on HOSSM's past experience, the expenses associated with transportation, staging and execution of work in these remote and hard-to-access locations result in materially higher unit costs than replacement in areas nearer to the utility's operating base in Sault Ste. Marie. As such, the number of planned unit replacements is expected to vary materially year-over-year throughout the Plan period, depending on the location of circuits targeted for replacement.

As discussed further in the METSCO ACA Report (Appendix B) HOSSM currently collects only a limited amount of information on the health condition of non-wood structures. This affected the number of criteria included in the derivation of their respective Health Indices in the METSCO report. As HOSSM's integration with Hydro One continues, HOSSM will align its maintenance and inspection criteria with those of Hydro One, revisiting the condition scoring approach for its support structures (along with other types of equipment) over time.

Other Assets

Aside from the station and transmission line equipment, HOSSM operates several other asset classes, including SCADA equipment, radio communication equipment, office computer software and hardware, small tools and testing implements, and other office and storage supplies and implements.

Assets in the General Plant category are maintained and planned for replacement or refurbishment in accordance with the process described in Section 3.1.3.3. Among the largest decisions regarding the General Plant category anticipated to be made over the plan period is the continuation of the current lease of HOSSM's office facility, set to expire at the end of 2019. Given that HOSSM is in the early stages of exploring this decision, this iteration of the Plan assumes that the lease continues throughout the Plan period.

HOSSM also operates a small fleet of vehicles, including one bucket truck, 18 trucks and SUVs, six snowmobiles, and six off-road vehicles, along with a variety of trailers. HOSSM maintains a limited amount of spare equipment and implements inventory at the operating centre and throughout its service territory, stored on stations sites.

Over the Plan period, HOSSM plans to invest modest amounts of capital resources into the regular upkeep and replacement of its General Plant assets. The largest investments anticipated to take place in the General Plant category over the Plan period is the purchase of a land parcel required to construct the new Greenfield TS, and the construction of an indoor storage facility for HOSSM's spare equipment and other implements.

3.2.3 EQUIPMENT-RELATED RELIABILITY PERFORMANCE

Line Equipment

Over the historical 2012-2017 period, HOSSM experienced defective equipment-related outages across 24 of its circuits. Five of these circuits, depicted on the figure 3-18, are responsible for 84% of total outage minutes over that timeframe.

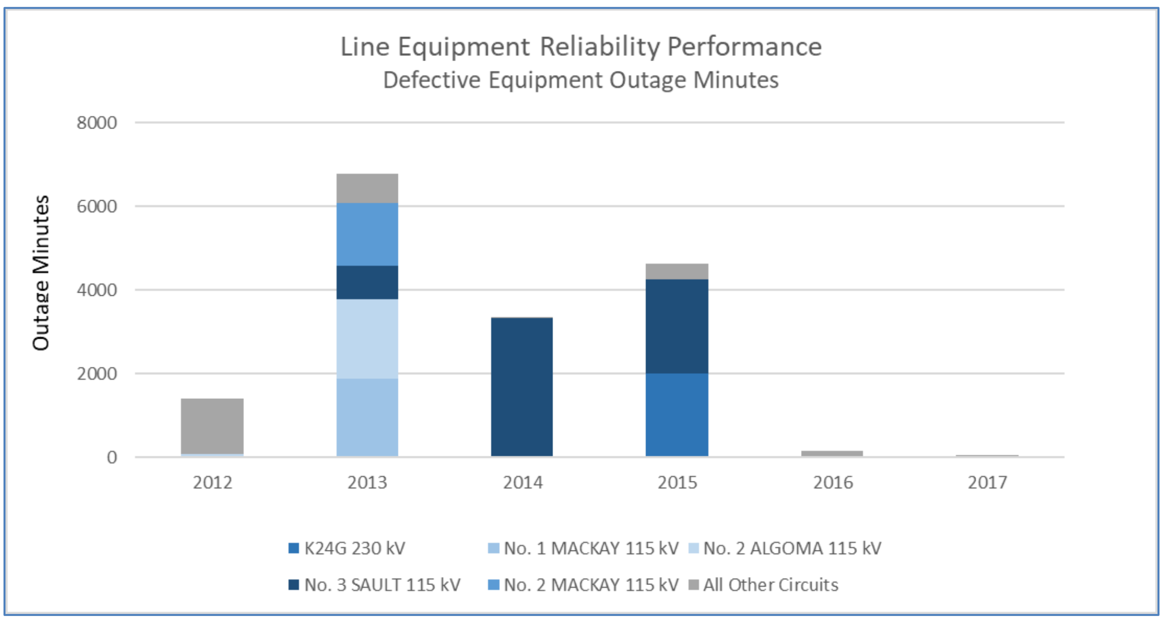


Figure 3-18: Defective Line Equipment Outage Minutes

As noted earlier, 39% of all line defective equipment outage minutes (occurring over nine outages) affected the Sault #3 Line, which HOSSM plans to re-conductor and replace the deteriorated wooden structures over the course of the Plan period (see ISD # SR-02 in Section 4.9). Of the five circuits depicted, HOSSM also plans to undertake wood structure replacement work on the Number 2 Algoma circuit (See ISD # SR-01). However, aside from the Sault #3

Line, equipment-related outage statistics do not present any meaningful patterns pointing at deteriorating performance of line equipment.

Station Equipment

Over the historical period, equipment-related outages occurred across ten of HOSSM's stations, as depicted on figure 3-19.

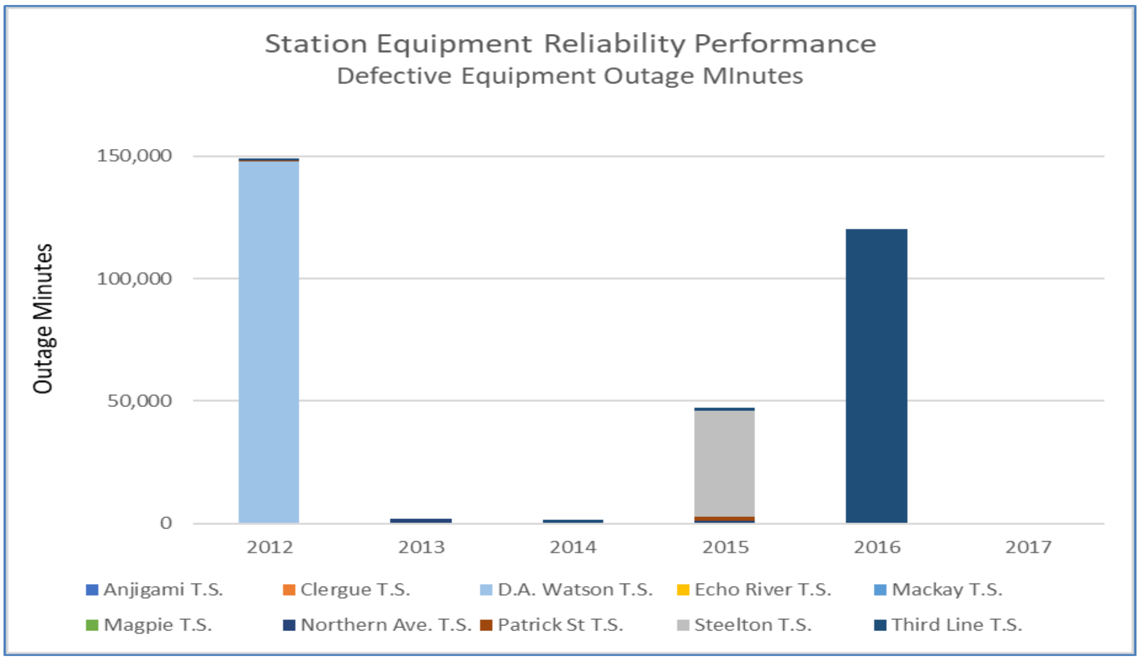


Figure 3-19: Defective Station Equipment Outage Minutes

While several of these equipment outages were lengthy (such as the 2012 Transformer outage at Watson TS and the 2016 Shunt Reactor Outage at Third Line TS), all events were singular in nature, without any repeatable patterns aside from several minor issues addressed by way of reactive maintenance.

3.3 ASSET LIFECYCLE OPTIMIZATION AND RISK MANAGEMENT

The objective of HOSSM and Hydro One's Asset Management process, including their elements such as the ARA and IPP is to optimize the lifecycle of installed assets by conducting comprehensive, multi-factor, evidence-based analysis when assessing both asset and system needs. Asset condition is the main factor along with reliability performance, customer needs and analysis of trouble reports and testing data in determining capital system investments. HOSSM seeks to ensure that all of its asset replacement, refurbishment or modification decisions incorporate the objectives of maximizing the expected service life of its assets.

Key factors in this analysis are the results of inspections and technical testing work conducted by HOSSM's staff and external contractors. As evidenced by the findings of the METSCO ACA report, the majority of HOSSM's assets are in Good or Very Good condition, suggesting prudent asset management and a balanced approach to asset intervention – by way of maintenance or replacement activities.

Where inspections and testing reveal individual issues of concern that warrant further investigation, HOSSM and its predecessor have historically commissioned technical reports from external expert consultants. These reports provide HOSSM staff with expert opinions on the issues at hand and are informed by industry best practices and the local conditions. In this manner, HOSSM confirmed the Poor condition of conductors on its Sault #3 Line, as confirmed by the Kinectrics testing results (Appendix C). Similarly, the current strategy for asset lifecycle management of the existing population of relays is a function of recommendation provided by One Line in its study (Appendix E). Going forward, HOSSM will use the results of METSCO's ACA to inform its further data collection, tracking and analysis activities.
A notable example of HOSSM's attempt to prolong the lifecycle of installed assets is the utility's strategy for wood support structures. The factors associated with its service territory, such as large woodpecker populations, harsh weather conditions, among others, cause a comparably

faster deterioration of wood structure populations that at times require replacement as early as 15-20 years after installation, based on historical data. Given these circumstances, the utility's management made a strategic decision approximately 15 years ago to replace deteriorated wood structures with composite fibreglass installations, which are expected to withstand the challenges offered by HOSSM's operating environment better than wooden structures, offering a more optimal economic outcome for the utility and its ratepayers. To prolong the life of existing wooden structures that sustained a material amount of woodpecker damage, HOSSM crews utilize a special epoxy solution to patch up the damage made by woodpeckers on structures where this type of intervention is deemed to be practicable.

Another example concerning station assets, are the power transformers at Clergue TS. While METSCO's ACA study determined these units to be in the lower part of the Fair condition band (51% and 64% Health Indices), subsequent analysis determined that the low scores were related to a significant degree of oil leakage observed on transformer assets. HOSSM considered replacing both units over the course of this TSP, but as a part of the Needs Assessment process, opted for the replacement of transformer bushing gaskets – a significantly less costly solution expected to prolong the useful lives of the two transformers.

Asset condition and past performance are not the only planning drivers underlying the development of plans for replacement and refurbishment of assets. Considerations such as system operation efficiency, equipment standards and maintenance of acceptable operating parameters (e.g. local area supply adequacy, short circuit limits, etc.) constitute important inputs into the utility's planning process.

Accordingly, replacement and refurbishment projects may be reviewed for potential economic synergies, particularly where major modifications to station infrastructure are contemplated. When such cases present themselves, HOSSM reviews the available information to determine whether combining replacement activities at the same location carries operating benefits.

As the utility's integration with Hydro One progresses, HOSSM expects that its approaches to capital asset lifecycle optimization will undergo an extensive review and alignment with those of Hydro One. As the two entities' equipment standards, planning assumptions, and work execution practices converge over time, synergies and efficiencies for the benefit of its customers and shareholders are expected to be realized.

3.3.1 ASSET RISK MANAGEMENT

By adopting Hydro One's risk-based IPP approach for pacing and prioritization of its planned capital work program, HOSSM has significantly enhanced the rigour applied in the area of risk-based asset intervention planning in respect to its assets, as in the past, equipment-related risk assessments were conducted in a more informal manner only. As detailed in Section 3.1.3.3 of this plan, the current approach adopted from Hydro One is grounded in evidence-based assessment of each project's risk mitigation potential on the basis of three core risk dimensions – reliability, safety and environment.

Given that Hydro One's IPP approach utilizes a consistent and transparent framework for quantifying the probability and impact of potential consequences of asset failure, and incorporates input from a variety of stakeholders both at HOSSM and Hydro One, the current TSP is grounded in a practical framework that assigns higher value to projects that are seen to mitigate the greatest value of risk. As such, by way of ongoing integration activities, the current Plan has benefitted from an advanced risk management approach that is comparable to industry best practices, while retaining at its core the expert knowledge of the system issues on the part of HOSSM's asset managers.

4.0 CAPITAL EXPENDITURE PLAN

This chapter provides the details of the material capital projects that HOSSM plans to undertake over the 2018-2026 Plan period, along with an overview of the System OM&A expenditures supporting the capital plan, and other pertinent information regarding the elements of the planning process.

4.1 PLAN SUMMARY

4.1.1 EXPENDITURES BY MAJOR RRF CATEGORY

Figure 4-1 depicts the gross capital expenditures anticipated for each year of the forecast period across the four RRF planning categories

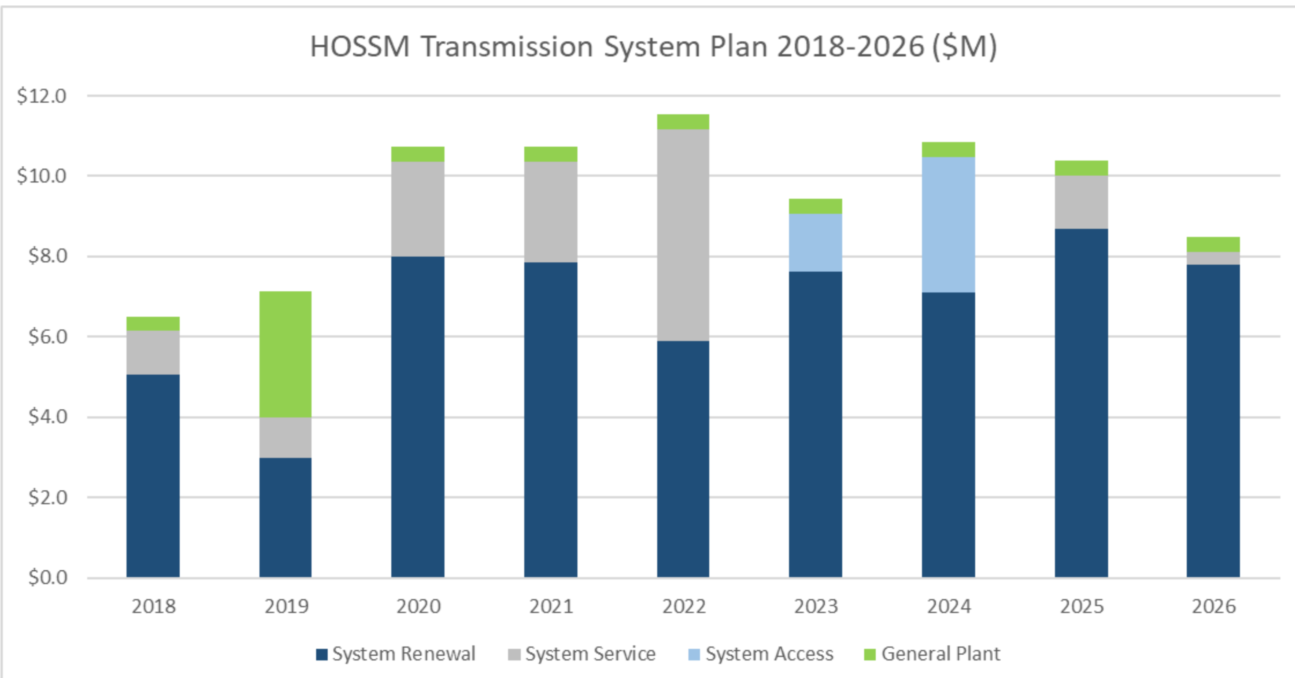


Figure 4-1: Plan Period Capital Expenditures

HOSSM plans to allocate over two-thirds of the Plan period expenditures (71%) to the projects in the System Renewal category, which includes replacements of transmission line wooden support structures, deteriorated line conductor, along with power transformers, breakers, switches, and other station assets. System Service represents the second largest category of projects, representing about 19% of the forecasted Plan period expenditures.

System Service projects aim to improve operational efficiency, and reliability of the HOSSM system, and ensure continued interoperability across the system. Of note is the fact that System

Service investment project scopes planned for the 2018-2026 periods include replacements of station assets, such as Protection Relays and Power Transformers.

In all cases, the units subject to replacement are in a deteriorating condition or have been determined to be obsolete. HOSSM elected to include these projects in the System Service category, since they are primarily driven by improving or maintaining the system's operational capabilities, with renewal of aged or obsolete units providing an additional justification.

There is only one planned System Access project for the duration of the Plan, which is the Spare Transformer Installation at the Echo River TS (ISD# SA-01), identified as a "wires-only" solution in the course of the 2014 Regional Planning process, and subsequently confirmed as desirable through Customer Engagement work with the customer, Algoma Power Inc. ("API"). While HOSSM expects API to participate in the funding of this project as per the Transmission System Code ("TSC") cost responsibility rules, HOSSM elected to include the gross project capital costs into the Plan expenditures at this time. The project's forecasted cost amounts to about 6% of the total forecasted Plan period expenditures.

Rounding out the Plan period expenditures is the General Plant category, which represents approximately 5% of total Plan period expenditures. Aside from regular upkeep of HOSSM's IT and Fleet assets, this category includes an acquisition of a land parcel to enable the construction of a new consolidated Greenfield TS (ISD #SS-01) and the construction of an indoor storage facility for replacement parts and small equipment.

4.1.2 EXPENDITURES BY MAJOR EQUIPMENT CATEGORY

Table 4-1 depicts the anticipated breakdown of the Plan period capital expenditures by major equipment category driving the investment. In providing this breakdown, HOSSM notes that it categorized the investments according to the main type of equipment underlying each project, whereas a number of projects also include replacements or modifications to other types of assets.

Accordingly, the table provides an indicative breakdown only, and should not be interpreted as a detailed forecast of capital additions across asset classes.

Table 4-1: Planned HOSSM Capital Expenditures by Major Asset Category ($M)

Asset Type	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total	Percentage
Lines	$5.1	$3.0	$7.0	$7.0	$4.0	$4.0	$4.0	$4.0	$4.0	$42.1	49%
Power Transformers	$0.0	$1.0	$2.4	$3.4	$7.0	$2.7	$2.4	$3.4	$0.0	$22.1	26%
Breakers and Switches	$0.0	$0.0	$1.0	$0.0	$0.2	$1.0	$2.2	$5.0	$4.1	$13.4	16%
P&C	$1.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.0	$0.0	$2.1	2%
Other Station Equipment	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$2.2	3%
Land Acquisitions	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.0	2%
Storage Facilities	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8	0.9%
Other General Plant	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$1.1	1%
Total	**$6.5**	**$7.1**	**$10.7**	**$10.7**	**$11.5**	**$8.0**	**$8.9**	**$13.7**	**$8.5**	**$85.7**	**100%**

Nearly half of total expenditures are anticipated to be allocated to line infrastructure – primarily replacement of deteriorated wood structures on 10 HOSSM circuits, along with conductor replacement on Sault #3 Line. Another 26% of planned expenditures, spanning System Access, Renewal and Service investment categories is dedicated to the transformer fleet. 16% of expenditures have been allocated for replacement of obsolete and deteriorated station breakers and switches and supporting infrastructure, with several allocation categories below 10% of the total Plan expenditures allocated to other station and General Plant categories.

4.1.3 EXPENDITURES IDENTIFIED THROUGH THE REGIONAL PLANNING PROCESS

As confirmed by the May 28, 2018 IESO letter provided in Appendix A, the last Needs Assessment undertaken in the course of the Regional Planning Process for the East Lake Superior planning zone took place in 2014, identifying no projects that required coordinated planning. Consistent with this conclusion, the current Plan does not contain any projects developed on the basis of coordinated planning. However, the Plan does contain a single project, namely a Spare Transformer Installation at Echo River TS (ISD# SA-01), identified among the "wires-only" solutions discussed in the course of the regional planning. The next round of regional planning is not required to commence until 2019. HOSSM will adjust the future iterations of this Plan, on the basis of any incremental findings in the course of the future Regional Planning activities.

4.1.4 CAPITAL PLANNING PROCESS INFORMATION

In preparing this Plan, HOSSM leveraged the planning processes discussed in detail in Section 3.1.3 of this Plan, which represent the parts of HOSSM's ongoing Asset Management Process. Among the most significant changes to the planning processes underlying the preparation of this TSP is the adoption of Hydro One's ARA and IPP frameworks discussed in Sections 3.1.3.2 and 3.1.3.3 of the preceding Chapter.

In preparing this Plan, HOSSM assumed inflation of 1.2% and the combined productivity and stretch factor of 0.0% for the entirety of the Plan period. As further substantiated in Exhibit D, Tab 1, Schedule 1 these assumptions are grounded in the results of the Total Factor Productivity study performed by Power System Engineering Inc. ("PSE") for Hydro One Transmission, into the operations of which HOSSM is being incorporated over the planning period. The PSE study and other supporting information is filed as a Exhibit D, Tab 1, Schedule 1, Attachment 1 of this application.

4.1.5 PLAN PERIOD SYSTEM OM&A EXPENDITURES

To support the execution of HOSSM's planned capital work program and maintain the safe and reliable operation of the system over the 2018-2026 Plan period, HOSSM anticipates to spend an average of $11.3 million per year in Operations, Maintenance and Administration ("OM&A") expenditures over the plan period.

In addition to supporting regular ongoing operations, HOSSM anticipates dedicating a material amount of OM&A expenditures to the process of aligning its Asset Management function with the policies, standards, and operating practices of Hydro One, including the remaining work to complete digitization, transfer and consolidation of HOSSM's asset data in Hydro One's IT systems, along with planning for, and eventual adoption of Hydro One's maintenance and inspection practices, which include a number of procedures not currently undertaken by HOSSM. The result of this alignment will be a more effective and efficient work planning and execution program that will reduce costs and rates for customers.

4.2 CAPITAL EXPENDITURE PLANNING PROCESS OVERVIEW

This section provides information on the key features of HOSSM's capital planning process, in addition to those already described in detail in Section 3.1 of the preceding chapter, which covers HOSSM's Asset Management process.

4.2.1 PLANNING OBJECTIVES, ASSUMPTIONS AND CRITERIA

As a responsible owner and operator of assets comprising its transmission system, HOSSM reviews and updates its capital plans on an annual basis as an integral part of its Asset Management process discussed in Chapter 3, to incorporate any emerging information regarding condition and operating performance of its assets, along with inputs obtained in the course of the ongoing Customer Engagement activities, customer applications to connect or modify the existing connections to the HOSSM system, and other emerging factors, as relevant.

A significant development that affected the scope and nature of the planning assumptions and criteria utilized in the development of this Plan is the acquisition of HOSSM's predecessor GLPT by Hydro One Inc., and the ongoing incorporation of HOSSM into the Hydro One transmission system. Among the benefits of the acquisition achieved to date is the incorporation of Hydro One's ARA and IPP frameworks into HOSSM's asset management process. While both of these frameworks are discussed in detail in Section 3.1.3 of the preceding Chapter, their core contribution to the planning process is the enhancement of HOSSM's reliance on systematic, objective, and data-driven evaluations when assessing asset and system needs or projecting the anticipated risk mitigation benefits in the process of project prioritization.

Section 3.1.3.3 of this Plan details the specific steps comprising the investment planning process for each of the four investment categories included in this Plan. Investment Summary Documents ("ISDs") for all material capital projects and programs comprising the forecasted Plan period expenditures above the materiality threshold are provided in Section 4.9.

As discussed in Section 3.1.1, the full consolidation of HOSSM's asset management function is expected to continue throughout the current Plan period, as issues including equipment maintenance and replacement standards, capital work execution, will require careful planning and implementation over the coming years. In the course of this work, HOSSM expects to gradually update the planning criteria used in preparation of its capital expenditure plans, to be reflected as appropriate in the future iterations of this TSP.

4.2.2 ABILITY TO CONNECT NEW LOAD

HOSSM's capital planning process incorporates the evaluation of anticipated changes in load requirements from its existing customers, along with the applications for connection from new customers. At this point, HOSSM is not aware of any firm plans from its existing customers to increase their load capacity requirements in the magnitude that warrant planning of any capacity upgrade projects. Similarly, there are currently no new load customers seeking connection to the HOSSM service territory.

4.2.3 NON-TRANSMISISON SYSTEM ALTERNATIVES TO RELIEVING CAPACITY CONSTRAINTS

While HOSSM possesses no information to indicate that any of its transmission facilities currently present constrains to connection or expansion of existing connection facilities by load or generator customers, the issue of any planning area capacity constraints and alternative means of relieving them (including though Conservation and Demand Management options) will be explored in the next round of Regional Planning work for the East Lake Superior region expected to commence in 2019.

Moreover, several HOSSM customers have embedded generation and storage facilities connected to their respective distribution systems, amounting to the total of 195 MW of embedded resources, which, among other benefits, help manage the aggregate system capacity needs.

4.2.4 SYSTEM CAPABILITY ASSESSMENT FOR RENEWABLE ENERGY GENERATION

As discussed in Section 2.3.2 HOSSM system is currently an injection point for approximately 699 MW of transmission-connected renewable hydroelectric and wind generation resources, with another 195 MW of renewable and industrial by-product (steam) generation and storage embedded within the distribution networks of its customers, for a total of 894 MW of generation and storage resources connected to the HOSSM system directly and indirectly. As indicated in Section 3.2.1, HOSSM's transmission system also plays an important role in enabling inter-area transfer of generation resources from other parts of the province towards the load centres beyond its service territory.

As of the time of preparation of this TSP, HOSSM is unaware of any planned renewable generation projects that would require it to plan for expansion of system capacity at a local or regional level. Accordingly, this iteration of the TSP does not include any investments driven by enablement of renewables or any other form of generation.

4.3 LIST OF MATERIAL CAPITAL EXPENDITURES

This section contains a listing and brief descriptions of projects and programs in excess of HOSSM's materiality threshold of $0.2 million per year, comprising the Plan period capital program. Detailed Investment Summary Documents for each project and program are provided in Section 4.9.

4.3.1 SYSTEM ACCESS

The current Plan includes only one System Access project, namely to install a spare station transformer at HOSSM's Echo River TS, identified in the course of the 2014 Regional Planning process and subsequently raised in the course of HOSSM's Customer Engagement activities with API. While HOSSM expects API to participate in funding of this project aimed at enhancing supply reliability for API customers at this point of its system's interconnection with the HOSSM system, the details of the cost-sharing arrangement are yet to be confirmed. Accordingly, the project's entire capital cost estimate is included in this Plan, to be further amended as the discussions with API regarding its funding contribution proceed.

Table 4-2: System Access Projects

Project	Description	Driver(s)	Execution Timeline	Capital Cost
SA-01. Echo River TS Spare Transformer	Install a new 230/115/35 kV spare transformer to supplement the existing single transformer at the Echo River TS.	System Reliability, Customer Request	2023-2024	$4.8M

4.3.2 SYSTEM RENEWAL

There are seven projects and one program exceeding the annual materiality threshold in the System Renewal category. Brief project descriptions are provided in the table 4-3.

1 **Table 4-3: System Renewal Investments**

Project	Description	Driver(s)	Execution Timeline	Capital Cost
SR-01. Wood Structure Replacement Program	Replace deteriorated wood support structures in or approaching Very Poor and Poor condition with composite fibreglass structures on 115 kV circuits No.1 Algoma, No. 2 Algoma, No. 3 Algoma, No. 2 High Falls, Steephill, Andrews, Hollingsworth; 230 kV circuit P21G, and 44 kV Anjigami circuit.	Equipment Condition, System Reliability	2018, 2022-2026	$24.8M
SR-02. Number 3 Sault Line Reconductoring and Wood Structure Replacement	Replace conductor and structures in Very Poor and Poor condition on the circuit that accounts for 39% of line equipment-related outage minutes over the 2012-2017 period.	Equipment Condition, System Reliability	2018-2021	$17.3M
SR-03. Third Line TS Transformer Replacement	Replace T2 station transformer at Third Line TS in Fair condition approaching Poor (51% Health Index Score).	Equipment Condition, System Reliability	2021-2023	$4.8M
SR-04. Northern Avenue TS Transformer Replacement	Replace T1 station transformer at Northern Avenue TS in Fair condition (62% Health Index Score).	Equipment Condition, System Reliability	2023-2024	$1.4M
SR-05. Watson TS Infrastructure Replacement	Replace metalclad switchgear at Watson TS with known mechanical operating issues that cannot be addressed through refurbishment and upgrade the bus structure to a “ring” design.	Equipment Condition	2024-2025	$4.7M
SR-06. Clergue TS Switchgear Replacement	Replace metalclad switchgear at Clergue TS with known mechanical operating issues that cannot be addressed through refurbishment.	Equipment Condition	2025-2026	$4.8M
SR-07. Echo River TS Circuit Breaker Replacement	Replace the degraded (50% Health Index Score) 230 kV circuit breaker with a new equivalent unit.	Equipment Condition	2020	$1.0M
SR-08. Steelton TS Breaker Upgrade	Replace obsolete minimum oil breakers in Fair condition at Steelton TS.	Operating Efficiency, System Reliability	2022-2024	$2.3M
Total System Renewal Projects				**$61.0M**

4.3.3 SYSTEM SERVICE

There are two projects and two programs comprising the System Service portfolio of investments over the 2018-2026 Plan timeframe. Table 4-4 provides brief descriptions for each initiative.

Table 4-4: System Service Investments

Project	Description	Driver(s)	Execution Timeline	Capital Cost
SS-01. New Greenfield TS	Consolidate existing Goulais and Batchawana TS assets in deteriorated condition into a single new Greenfield TS, with renewed assets, addressed clearance constraints and improved operating capabilities.	Operating Efficiency, Safety, System Reliability	2024-2026	$11.1M
SS-02. Steelton TS Disconnect Upgrade	Uprate disconnect switches at Steelton TS to ensure reliable operation and improve the efficiency of maintenance activities.	Operating Efficiency	2020-2024	$0.6M
SS-03. Station Protection Upgrade Program.	Upgrade technologically obsolete protection relays in Poor/Very Poor condition at Watson, Third Line and Hollingsworth TS.	Operating Efficiency, System Reliability, System Interoperability	2018-2025	$2.1M
SS-04. Consolidation Capital Program	Obsolete and non-conforming minor equipment replacements, engineering studies, tool and implement procurements anticipated to be required in the course of ongoing integration of HOSSM asset management function into Hydro One.	Operating Efficiency	2018-2026	$2.3M
Total System Service				**$16.0M**

4.3.4 GENERAL PLANT

HOSSM forecasted General Plant expenditures are comprised of two projects and one program. Table 4-5 provides an overview of these investments.

1 **Table 4-5: General Plant Investments**

Project	Description	Driver(s)	Execution Timeline	Capital Cost
GP-01. Greenfield TS Land Purchase	Purchase a suitable land purchase in the area north of Sault Ste. Marie to enable the planned construction of the Greenfield TS (ISD #S1).	General Plant	2023	$2.0M
GP-02. Third Line TS Storage Building	Construct a permanent indoor climate-controlled storage facility on the Third Line TS grounds for spares and equipment.	General Plant, Operating Efficiency	2019	$0.8M
GP-03. General Plant Renewal Program	Enable regular upkeep and replacement of HOSSM's IT hardware and software, vehicle fleet, tools, and office equipment.	Genera Plant, Safety	2018-2026	$1.1M
Total General Plant				**$3.9M**

4.4 SYSTEM DEVELOPMENT OVER THE FORECAST PERIOD

Based on the latest round of Customer Engagement discussions conducted in May of 2018, the absence of any generation or load connection applications, and the most recent update from the IESO as to the status of the Regional Planning process in the East Lake Superior planning region, HOSSM does not anticipate any significant changes to the planning requirements related to customer connection capacity or system configuration beyond the projects captured in the System Service investment category that would result in material changes to its system over the Plan period.

HOSSM anticipates that the combination of System Renewal and System Service projects that make up the bulk of the Plan period expenditures will materially improve the average health of its critical Line and Station infrastructure, currently found to be in deteriorating condition and flagged for follow-up on the basis of the METSCO ACA study provided in Appendix B.

Finally, HOSSM anticipates certain incremental changes to the types, models, or materials used in its capital program as a result of ongoing integration with Hydro One, which will include gradual transition to Hydro One’s equipment standards, environmental and safety policies and practices. Decisions regarding any such changes over the Plan period will be made on the basis of detailed evaluation of costs and benefits and will be incorporated into the future iterations to this TSP using the planning tools and processes described in Sections 3.1 and 4.1.

4.5 CUSTOMER PREFERENCE, TECHNOLOGICAL OPPORTUNITY AND INNOVATION

As noted in Section 3.1.3.2 HOSSM engages its customers on the regular basis to discuss the customers evolving needs, plan for and address ongoing and emerging operating needs, and solicit customers' feedback as to its own capital plans. The preferences and priorities for HOSSM's customers are related to reliability, with industrial customers emphasizing their preference for reduction of frequency of outages and LDC customers encouraging HOSSM to take steps to prevent lengthy outages that negatively affect their residential and small commercial customers, particularly in cold winter months due to the customers' widespread reliance on electric heating. All types of customers also express the preference for paced and gradual investments to help manage their electricity bills.

HOSSM believes that the current Plan strikes an appropriate balance to addressing these priorities. By undertaking to finance its capital program over a nine-year Plan period through depreciation funding, adjusted by the Revenue Cap Incentive Rate index, HOSSM is providing its customer base with a significantly longer capital expenditure forecast horizon than in the past, where HOSSM and its predecessor GLPT typically sought capital budget approval for two years at a time. A nine-year capital plan aiming to contain the expenditures within the envelope of index-adjusted depreciation funding helps customers budget their electricity costs, while avoiding any step increases.

Moreover, the current Plan contains System Renewal and System Service investments targeting HOSSM station and line assets in the most deteriorated condition, includes an investment to provide backup power supply at the point of connection of one of HOSSM's LDC customers, a replacement of a transformer in deteriorating condition at the station that connects the majority of its load, and addresses equipment problems on a circuit responsible for nearly 40% of equipment outage minutes over the last five years. By executing these and other planned capital projects, HOSSM will enhance the reliability of supply for both the directly-connected industrial and generation customers, and the residential and commercial customers embedded in the service territories of two LDCs served by HOSSM's transmission system.

As discussed throughout Chapter 3, the planning processes utilized in preparation of this TSP display a number of advanced and innovative approaches relative to HOSSM's previous planning documents, including a comprehensive ACA, and new ARA and IPP frameworks adopted from Hydro One. A number of System Renewal and System Service investments, such as the upgrades to Protection Relays at Watson, Hollingsworth and Third Line transmission stations, and the replacement of minimum oil breakers at Steelton TS, aim to replace the technologically obsolete equipment with contemporary units that utilize newer technologies.

Beyond the above-noted improvements, this Plan does not contain any investments directed specifically at implementation of newer, experimental technologies. HOSSM believes that it is appropriate for a plan financed solely by depreciation funding to prioritize investments in upkeep and operational improvements of core transmission system infrastructure, deferring consideration of any new technologies for a later time, when its standards and practices have been fully aligned with those of Hydro One, and any potential new technologies can be properly tested through a rebasing application process.

4.6 SYSTEM OM&A EXPENDITURES

To support the safe and reliable operation of its transmission system over the Plan period, HOSSM anticipates its average annual System OM&A expenditures to equal approximately $11.3 million per year for the duration of the Plan period, increasing from $10.7 million in 2019 to $11.8 per year at the end of the plan. These forecasted volumes are consistent with the historical levels embedded into the revenue requirement underlying the current Revenue Cap Incentive Rate-Setting model.

While the ongoing integration with Hydro One creates opportunities to realize a number of potential operating and capital synergies discussed in Section 2.2.3, HOSSM expects that the gradual adoption of Hydro One’s asset management policies and practices may result in the need for incremental increases to its current Maintenance expenditures in particular, as Hydro One asset management processes include a number of equipment maintenance and inspection procedures that HOSSM does not currently undertake on a regular basis. These incremental expenditures, along with the implementation costs of other integration projects may offset some of the benefits anticipated from synergies in the early years. Overall, however, HOSSM expects to manage its total annual OM&A expenditures within the envelope commensurate to historical levels.

4.7 PAST PERIOD INVESTMENT SUMMARY AND COMPARISON WITH PLAN PERIOD CAPITAL EXPENDITURES

4.7.1 HISTORICAL EXPENDITURES SUMMARY

While this is HOSSM’s first comprehensive TSP utilizing the four RRF investment categories, HOSSM made its best efforts to allocate the past five years (2013-2017) of capital expenditures across the RRF planning categories. Table 4-6 provides a side-by-side comparison of historical and Plan period expenditures across the four investment categories.

Table 4-6: Historical and Plan Period Capital Investment Summary

	Historical					**Plan**									**Plan Total**
Category ($M)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Plan**
System Access	$0	$0	$0	$0	$0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4	$3.4	$0.0	$0.0	**$4.8**
System Renewal	$2.3	$3.3	$7.1	$6.5	$10.2	$5.1	$3.0	$8.0	$7.9	$5.9	$7.6	$7.1	$8.7	$7.8	**$61.0**
System Service	$0.6	$0.2	$0.1	$0.5	$0.7	$1.3	$1.3	$2.6	$2.8	$5.5	$0.3	$0.3	$1.6	$0.6	**$16.0**
General Plant	$0.5	$0.5	$1.3	$1.9	$4.1	$0.1	$2.9	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	**$3.9**
Total	**$3.3**	**$4.0**	**$8.5**	**$8.9**	**$15.0**	**$6.5**	**$7.1**	**$10.7**	**$10.7**	**$11.5**	**$9.4**	**$10.8**	**$10.4**	**$8.5**	**$85.7**

A variance analysis of expenditure levels and types between the historical and Plan periods for each of the categories is found in Section 2.1. HOSSM notes that the level of detail available for this comparative analysis is impacted by limited access to information of appropriate level of detail related to the historical expenditures

4.7.2 COMPARATIVE TRENDS IN CAPITAL EXPENDITURES

In addition to mapping historical capital expenditures to the four RRF investment categories, HOSSM undertook to provide a high-level comparative perspective of trends in HOSSM’s capital expenditures between the historical and Plan periods on the basis of functional allocation of expenditures across the major equipment categories. As noted earlier in this Plan, this allocation reflects grouping on the basis of work performed on the largest asset underlying a particular program or project and should not be interpreted as representing capital additions across discrete asset classes. Given the range of investments undertaken over the historical period, HOSSM elected to group a number of them into larger categories to enable a high-level assessment of trends across consistent categories. Figure 4-2 showcases the results of this comparative assessment, grouping the historical and Plan period expenditures into four broad categories.

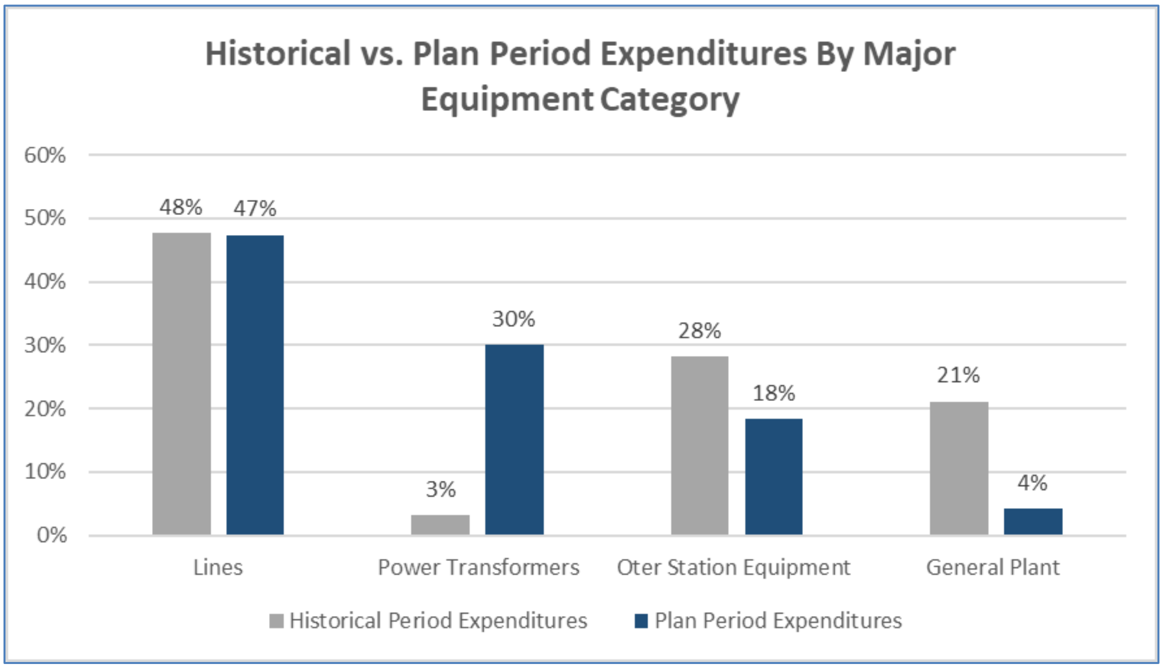


Figure 4-2: Historical vs. Plan Period Expenditures by Major Equipment Category

As evident from the above figure, HOSSM will allocate a virtually equivalent portion of its Plan period capital expenditures to line work as it did in the last five years. A materially higher portion of Plan period expenditures is allocated to work on its fleet of power transformers, a category that was a comparatively minor driver of expenditures in the historical period. The portion of Plan period capital spend planned for other station equipment work is smaller in relative terms than during the historical period, largely explained by significant investments into replacements of HOSSM's power transformer fleet planned for the 2018-2026 timeframe and appropriately supported by comprehensive asset condition evidence. Finally, and driven largely by the value of several land transactions undertaken by HOSSM's predecessor over the historical period, and anticipated efficiencies targeted through the integration with Hydro One, HOSSM Plan period General Plant expenditures represent a significantly smaller portion of the anticipated spend than they did over the 2013-2017 historical period.

Overall, HOSSM believes that a shift in relative expenditure allocations away from General Plant towards station infrastructure evident from the above figure, represents a responsible way to manage its asset base and operate its system over a nine-year period that coincides with an ongoing corporate integration and is characterized by funding constraints imposed by the Revenue Cap Incentive Rate framework.

4.8 EXTERNAL BENCHMARKING SUPPORTING THE REASONABLENESS OF THE INVESTMENT PLAN

Since the current Plan does not propose any capital or OM&A expenditures in excess of the levels already embedded into HOSSM's last approved Revenue Requirement, a benchmarking study confirming the reasonableness of HOSSM's expenditures would not be instructive. However, in preparing this Plan, HOSSM staff referred to the Total Factor Productivity study prepared by Power System Engineering Inc. ("PSE") for Hydro One Transmission. Moreover, as the integration between HOSSM and Hydro One continues, HOSSM plans to utilize a range of studies prepared by the Electric Power Research Institute ("EPRI") on a number of topics concerning asset management best practices. HOSSM will leverage these insights to continually improve the efficiency and cost effectiveness of its operations.

4.9 CAPITAL PROJECT JUSTIFICATIONS

This section of the TSP contains investment summary documents for the capital projects exceeding the HOSSM materiality threshold of $0.2 million. Table 4-7 provides a summary of all plan Period investments by major category, along with the Investment Summary Document Numbers ("ISD") for each category.

Table 4-7: Plan Period Investments Overview Summary Investment Category

Investment Category	Expenditure Drivers	Representative Activities	Investment Examples	Plan Total ($M)
System Access *ISD# SA-01*	Customer Requests	Customer Connections, Service Upgrades	Echo River TS spare Transformer Installation.	**$4.8** *6%*
System Renewal *ISD# SR-01 to SR-08*	Asset Failure	Reactive replacement of assets failed in service	No planned projects.	**$61.0** *71%*
	Assets at the End of Life due to Condition, Failure Risk, or Functional Obsolescence	Wood Structure and Conductor Replacements, Transformer and Relay Replacements.	Sault #3 Line Upgrade; Wood Structure Replacements; MacKay TS Relay Replacements.	
System Service *ISD# SS-01 to SS-04*	System Reliability and Operational Efficiency Improvements	Station Consolidation, Protection and Control enhancements	Greenfield TS Station Consolidation, Relay Replacement Program	**$16.0** *19%*
General Plant *ISD# GP-01 to GP-03*	Non-system physical plant and computer software.	Land Acquisition for Station Expansion; IT and Fleet Replacement. Ongoing upkeep of fleet and IT assets, real estate needs to enable station consolidation	Third Line TS Storage Building, Greenfield TS Land Purchase	**$3.9** *5%*

Investment Summary Document ("ISD") Listing

Investment Summary Document – System Access

SA-01 ECHO RIVER TS SPARE TRANSFORMER

Start Date:	Q1 2023	**Priority:**	High
In-Service Date:	Q4 2024	**Total Cost ($M)**	4.8
Trigger(s):	Customer Request, System Access, Regulatory Compliance		
Outcomes:	Enhance Reliability, Customer Satisfaction, Facilitate Compliance with Ontario Resource and Transmission Assessment Criteria (“ORTAC”) Load Restoration Standards.		

Objective:

Enhance supply reliability at the Echo River TS station by installing a new 230/115/35 kV spare transformer to supplement the existing single transformer at the Echo River TS.

Need:

Service continuity of distribution load connected to Echo River TS depends on a single 230/34.5 kV autotransformer T1 equipped with an Under Load Tap changer. During contingency situations at the station, distribution load restoration involves extending back up feed through a medium-voltage feeder from Northern Avenue TS, causing voltage drop due to length of the feed.

Load flow analysis indicates that back up feed will not be able to satisfy the load during winter peak, requiring rotating load shedding resulting in customer interruptions in the event of an outage at Echo River during the winter season. The health index of the existing T1 transformer is calculated to be 56% (Fair).[11] Given the deteriorating condition of the original unit, the need for a backup unit is further amplified. However, the replacement of the original transformer is not proposed for the period of this Plan given the low loading levels.

[11] All Health Index references in the ISD documents relate to the MTSCO Energy Solutions Asset Condition Assessment (See Appendix B of the application).

The issue of Hydro One Sault Ste. Marie's ("HOSSM")'s stations equipped with a single transformer, which in the past have led to longer outage restoration timelines than those prescribed by the Ontario Resource and Transmission Assessment Criteria ("ORTAC") standard (eight hours plus travel time) has been raised in the context of the 2014 Regional Planning process led by HOSM's predecessor Great Lakes Power Transmission ("GLPT"). The resolution of this issue has been identified as one of three "wires only" solutions at that time.

Most recently, the issue of backup supply at Echo River TS became a topic of customer engagement discussions with Algoma Power Inc. ("API"), whose system connects to the station. API has performed its own study, which found the transformer station upgrade to be the most economical solution. Given that API and its customers will be primary beneficiaries of the project, HOSSM expects API to make a funding contribution, consistent with the Transmission System Code ("TSC") cost responsibility rules. While HOSSM believes it to be prudent to include this project into the scope of its nine-year plan, the project's execution is contingent upon reaching a cost sharing arrangement consistent with the Transmission System Code cost responsibility rules.

Alternatives:

Alternative #1: Do Nothing:

Failing to act will expose the Echo River TS area distribution loads to relying on a single contingency during the winter peak periods. An outage during the winter season will require rotating outage schemes to supply the area. Moreover, the existing T1 unit is in "Fair" condition, meaning that its probability of failure is elevated and will continue to deteriorate over time. Moreover, doing nothing will leave the customer request and study from API unaddressed and potentially expose HOSSM to future instances of non-compliance with ORTAC standards. Based on these considerations, Alternative #1 is not recommended

Alternative #2: Augment the Northern Avenue Feeder:

Reconductoring the existing line from Northern Avenue would help alleviate the voltage drop concerns in the area exacerbated during contingencies at Echo River TS. However, the cost of reconductoring approximately 60 km of line is equivalent to the cost of a second transformer and will still leave customer load hinging on a single contingency. Moreover, aside from feeding Echo River TS during contingency events, there are no known issues with conductor performance or condition that would warrant its replacement over the Plan period. Alternative #2 is therefore not recommended.

Alternative #3: Use Removed Third Line TS T2 as back up:

The T2 transformer removed from service at Third Line TS project ISD# R3 may be considered as a short-term interim solution ahead of the proposed spare procurement at Echo River TS. This alternative is not recommended, as the T2 transformer unit from Third Line TS is not a dependable source of supply due to its age and deteriorated condition (51% Health Index score). This would result in additional costs if the T2 then failed. Alternative #3 is not recommended.

Alternative #4: Procure a new T2 Transformer

This is the recommended alternative, as it provides the sought after redundancy and addresses the issue of outage restoration timelines. A new unit could also become the primary transformer as the existing unit is showing signs of deterioration. Moreover, this option directly responds to customer preference as expressed by API on the basis of its own studies. As Alternative #4 addresses reliability and compliance issues, is aligned with Regional Planning observations and responds to customer preferences and needs, it is the recommended Alternative.

Investment Description:

A second transformer unit will be purchased and placed on a new transformer pad and spill containment at Echo River TS. Construction work will be performed during low load season such that loads can be served via Northern Ave TS feed during construction-related outages.

The unit will be connected in parallel with the existing unit, sourced through the same existing 230 kV breaker. However, the transformers will have separate Medium Voltage (34.5 kV) secondary breakers.

Project Costs

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)*	-	-	-	-	-	$1.4	$3.4	-	-	$4.8

**Capital contribution from API is expected for this project. Gross capital cost estimates are provided at this point as the cost responsibility discussions have not been finalized.*

Investment Results and RRF Outcomes

Customer Focus	• Responds to customer preference to address a known issue identified in Customer Engagement and noted among the "wires-only" solutions in Regional Planning.
	• Provides supply redundancy available under peak load conditions and superior to other alternatives of restoring power in terms of service quality.
Operational Effectiveness	• Enhances system reliability and operability under a variety of conditions.
Public Policy Responsiveness	• Enhances HOSSM's ability to comply with ORTAC load restoration timeline requirements.

Investment Summary Document – System Renewal

SR-01 WOOD STRUCTURE REPLACEMENT PROGRAM

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Various, to Q3 2026	**Total Cost ($M)**	24.8
Trigger(s):	Asset Condition, Reliability Risk		
Outcomes:	Operational Effectiveness, System Renewal		

Objective:

Continue the ongoing program of replacing wood support structures in or approaching the Very Poor and Poor condition. Condition is primarily determined by the 2018 METSCO Asset Condition Assessment (“ACA”) found as Appendix B. Wood structures are proposed to be replaced with composite fiberglass equivalents to ensure longer operating lives given the condition issues such as wood pecker and carpenter ant damage, feathering, and pole top rot observed on existing structures (see Figure 1 below). A number of poles have reached Very Poor condition significantly earlier than their expected service lives.

Need:

A structure replacement study conducted by Pole Care was conducted in 2010 and assessed the overall health of the wood structures across the system. Structures determined to be in poor conditions were suggested to be replaced with composite pole types and steel cross arms. HOSSM has been undertaking the replacement program for the last six years and proposes to continue it throughout the duration of the Plan period. In 2018, HOSSM commissioned a comprehensive ACA study by METSCO, which confirmed that the number of deteriorating structures remaining on the system warrants continuation of the program.

Figure 1 – Circuit P22G Structure with Extensive Woodpecker Damage

Figure 2 showcases the current distribution of HOSSM support structures for which condition data is available (about 90% of total population).

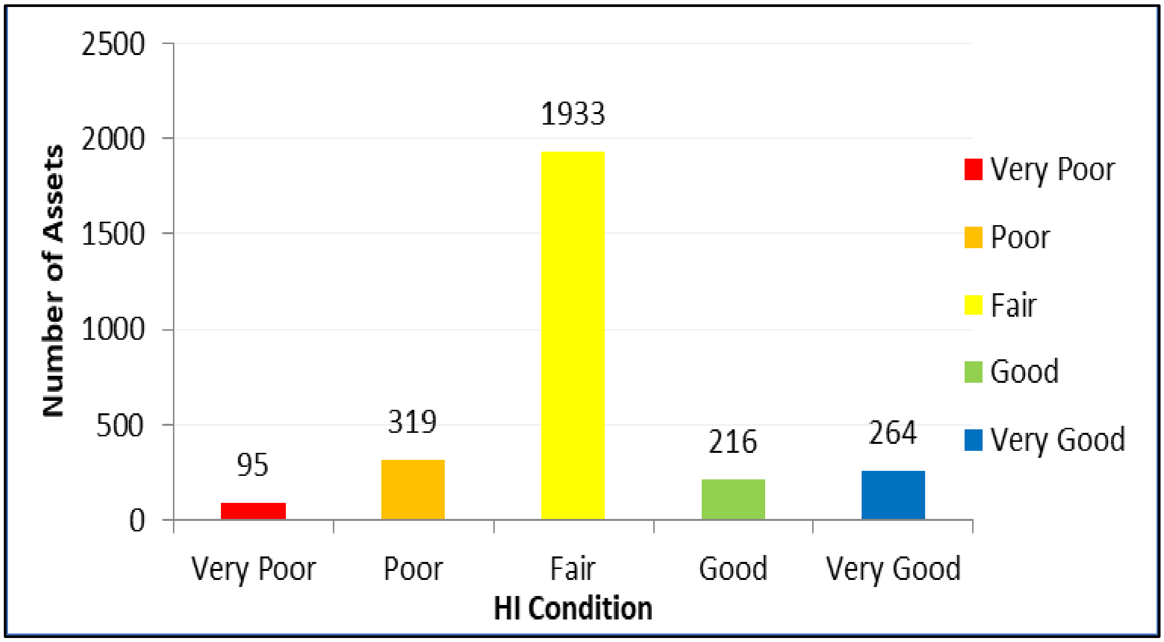
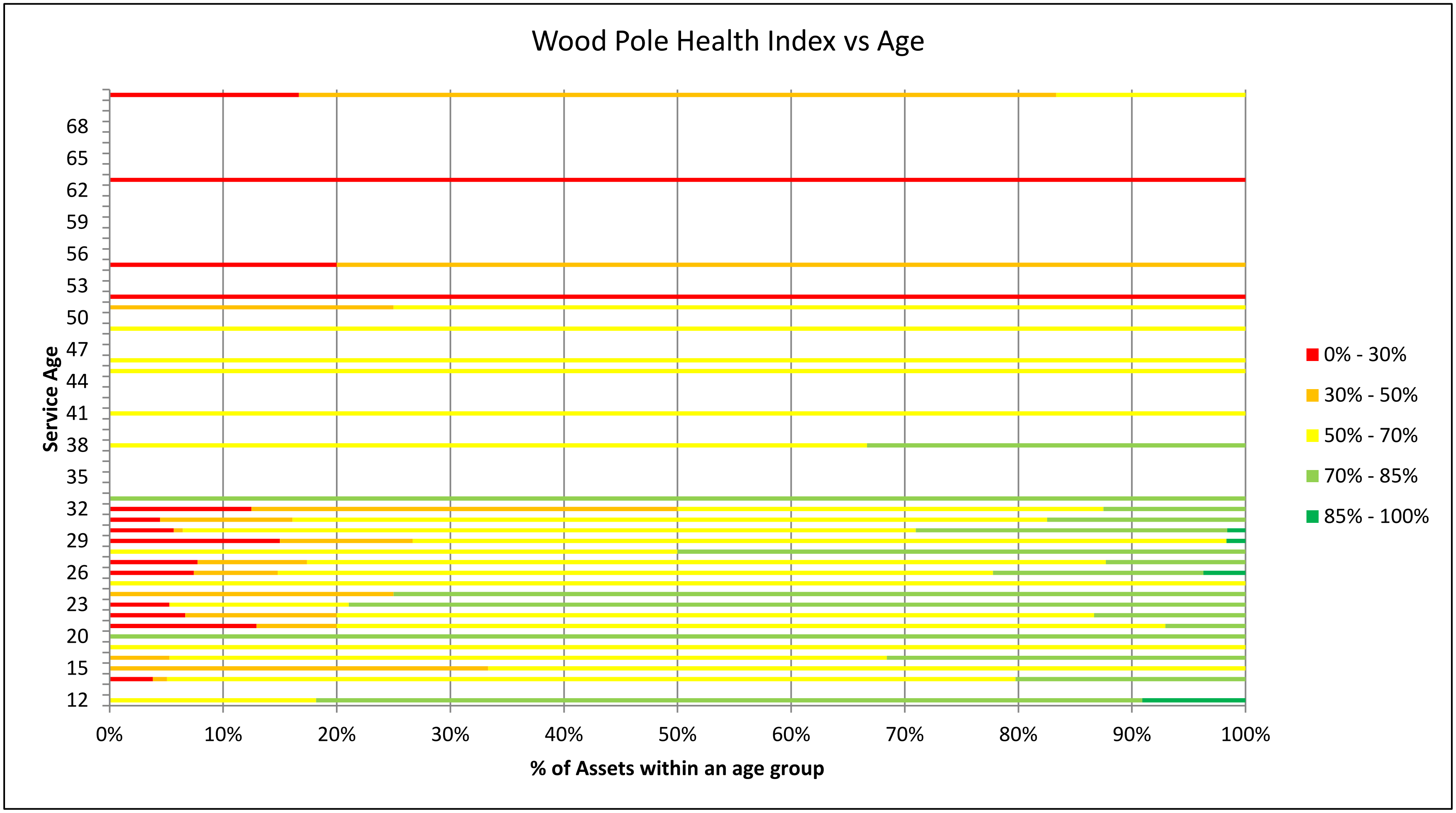


Figure 2 – Structures Health Index Distribution

All Very Poor, Poor and 98% of Fair structures depicted in the figure are Wood support structures. As Figure 3 showcases, a significant portion of HOSSM wood structures appear to reach Poor and Very Poor condition significantly ahead of the 40-year lifecycle typically used for the planning purposes when installing these assets.

For example, as many as 30% of wood structures aged up to 15 years appear to have reached Very Poor condition on the basis of information available for the Health Index calculation. Among the reasons for this is the extensive woodpecker damage that the wood structures are subjected to in the area, along with other issues such as pole top rot and carpenter ant damage. Installing composite fibreglass structures, consistent with the ongoing program for the last five years, provide a solution that aims to extend the lifecycles of deteriorated poles. Leaving the deteriorated structures in service compromises the reliability of line equipment and poses a degree of public and employee safety risk associated with falling equipment during reactive maintenance, or recreational activities that take place along HOSSM rights-of-ways, such as snowmobiling or hunting.

Composite structures are considered woodpecker and insect resistant, which is a significant benefit for these structures located in the Sault Ste. Marie area. Of the structures flagged for replacement in 2010, roughly 70 remains to be replaced along the 230 kV P21G and 115 kV Andrews 1 and 2 lines. On average, 30 to 70 structures can be replaced per year, depending on accessibility issues which affect the staging costs. There are additional issues on the Sault #3 Line with regards to ground clearance due to excessive conductor sag that can be addressed by the wood pole replacement program. Additional lines where structures are determined to be reaching their end of life by 2026 include 115 kV No. 2 High Falls, 115 kV Steephill and 44 kV Anjigami lines. Replacements of deteriorated structures are proposed for all of these circuits.



1 **Figure 3 – Wood Support Structures Health Index vs. Age Distribution**

Finally, the remote and difficult-to-access locations of a number of HOSSM's circuits significantly increases the time for reactive replacement given the access difficulties, particularly during the winter months described in Section 3.2.1 of the TSP, characterized by above-average snowfalls compared to most other parts of Ontario.

Alternatives:

Alternative #1: Do Nothing:

The "Do Nothing" alternative is not recommended, as the structures in or reaching critical condition will continue deteriorating over time, posing increasing reliability and safety concerns for staff and the public without replacement.

Alternative #2: Replace Structures with Equivalent Wood Structures:

While HOSSM could continue replacing the deteriorated structures with new wood structures, this alternative is not recommended due to the likelihood of similar issues being experienced with replacement units (e.g. woodpecker damage, feathering, top rot, and general loss of remaining strength), resulting in a shorter lifecycle for the replacement units and the higher overall capital costs for the asset class, as showcased in Figure 3 above.

Alternative #3: Run Existing Structures to Failure, Replacing on a Reactive Basis.

Although such an option may be more cost effective in the areas with higher customer and asset densities, this alternative is not recommended for HOSSM in light of the size of its service territory, the length of time to travel to site, access issues during the winter season and throughout of the year for some structures in particularly difficult areas, and the lack of resources and equipment to perform this work on a rapid basis as HOSSM uses outside contractors for structure replacements.

Alternative #4: Replace Structures with Fiberglass Composite Units:

This is the recommended alternative that seeks to extend the lifecycle of the structures by installing the units that are more resistant to some of the key degradation factors affecting the population. The option is also consistent with the program scope undertaken for the last five+ years, which was based on an earlier strategic decision to replace all deteriorating wood structures with composite units where possible.

Investment Description

Replace pole structures with composite poles and steel cross arms (predominantly in the H frame formation); consistent with the work program scope executed over the recent years. Along with the structure replacement, other equipment (e.g. insulator, etc.) will be replaced as well. Replacements will take place on the following circuits over the Plan period:

- No. 1 Algoma (115 kV)
- No. 2 Algoma (115 kV)
- No. 3 Algoma (115 kV)
- No. 2 HighFalls (115 kV)
- P21G (230 kV)
- Steephill (115 kV)
- Anjigami (44 kV)
- Andrews (115 kV)
- Hollingsworth (115 kV)

Note that capital investment for the wood pole replacement program will continue throughout the Plan period. However, the break in program expenditures for the 2019 to 2021 period corresponds to the timing of work on the Sault No. 3 line upgrades (ISD# SR-02), which includes conductor *and* associated wood support structure replacement to composite structures. The replacement of the wood structure with composite structures continues, but the associated expenditures are captured in the dedicated project budget.

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	$4.8	-	-	-	$4.0	$4.0	$4.0	$4.0	$4.0	$24.8

Investment Results and RRF Outcomes:

Operational Effectiveness	• Proactively addresses the risk of equipment failure in hard to access areas. • Enhances system reliability and addresses the key factors contributing to premature degradation of wood structures by replacing them with composite equivalents.
	• Mitigates safety risks for employees working on and around the assets in deteriorating condition, and members of public engaging in recreational activities along the rights of way.

Investment Summary Document – System Renewal

SR-02 SAULT #3 115 KV LINE RECONDUCTORING

Start Date:	Q3 2018	**Priority:**	High
In-Service Date:	Q3 2021	**Total Cost ($M)**	17.3
Trigger(s):	Asset Condition, Reliability Risk, Safety		
Outcomes:	Operational Effectiveness, System Renewal		

Objective:

Replace conductor and structures in “Very Poor” and “Poor” condition on the Sault #3 Line that accounts for 39% of line equipment-related outage minutes over the 2012-2017 period.

Need:

The Sault #3 115 kV transmission line is currently de-rated due to multiple sleeve failures and aging conductor. The line is among the most critical assets for enabling power flows across the system and serving local area supply customers as can be seen in Figure 4.

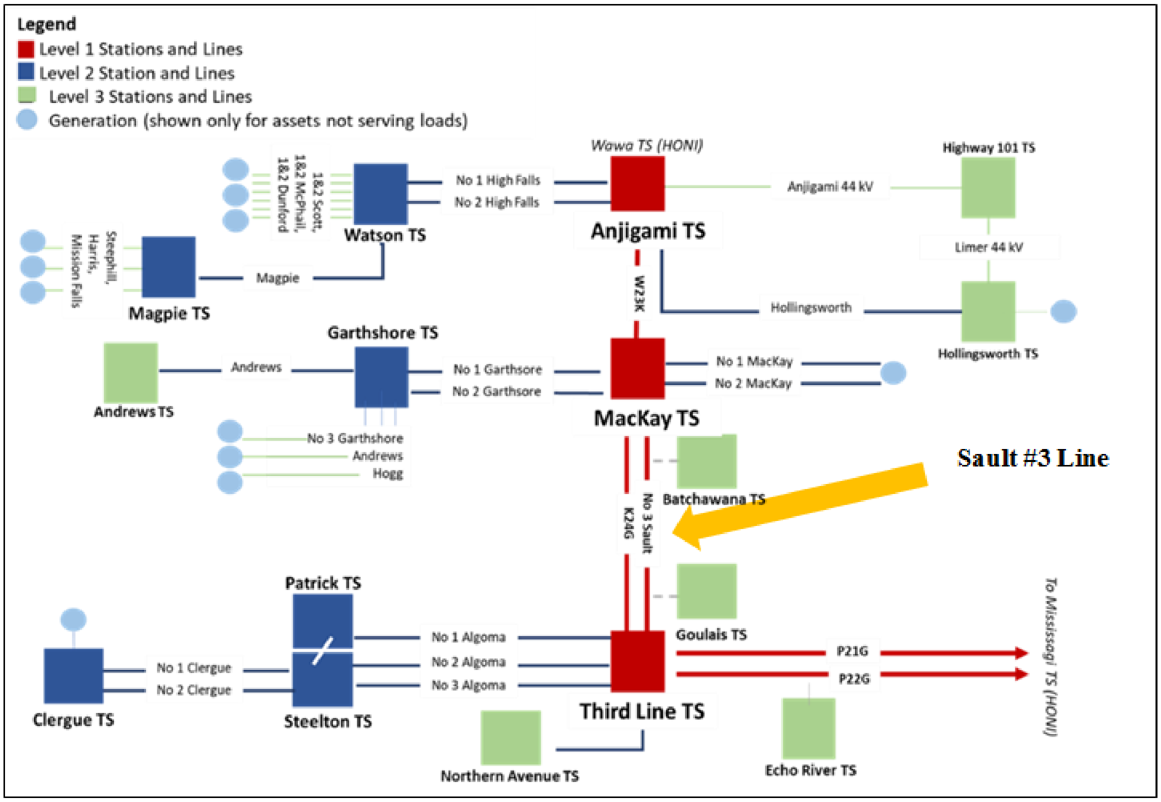


Figure 4 - Sault #3 Line in the Context of System Operation

Over the past years, sleeves have failed when the line was loaded to its rated capabilities. This poses a significant risk to public safety and is rendering the line inoperable under its rated conditions. Additionally, there are clearance violations associated with the conductor height. Along the conductor, there are "Poor" and "Very Poor" structures that can be replaced with composite poles (also included in the scope of this project) while the reconductoring is taking place.

The Sault #3 circuit accounts for 39% of all line equipment-related outage duration experienced over the 2013-2017 historical period; by far the worst feeder across the entire HOSSM system. To determine the condition of the conductor, HOSSM commissioned a laboratory test of the tensile strength and structural integrity (among other factors) based on a series of field splice samples obtained from the line as can be seen in Figure 5. See Appendix C for the Kinectrics testing results. The testing confirmed that the conductor is in Poor condition. In HOSSM’s assessment, these findings warrant replacement without further delay.

KINECTRICS REF. NO. : 415645 - GLP - 2014 - 03

ACSR 266.8 kcmil, 26/7. CCT : no, Line Section : No. 3 Sault 155kV Line, Structure No.: 486 490

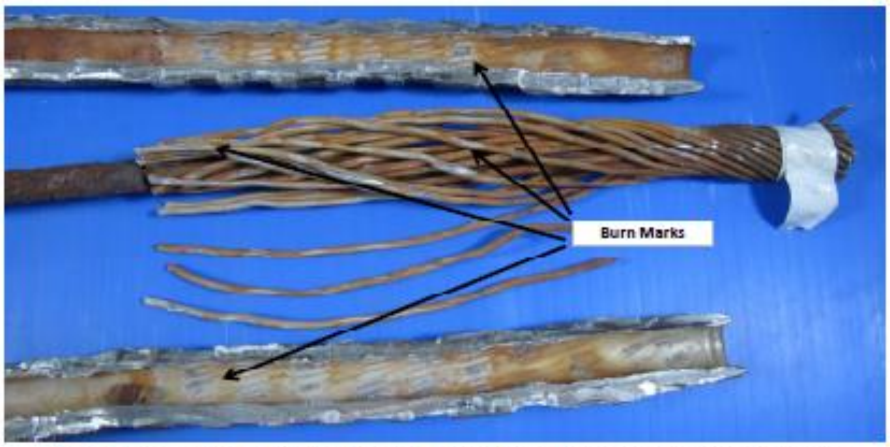


Figure 2b - Non-Failed Side - Burn marks on Alum Wires and Splice Inner Surface

Figure 3a - Failed Side - Burn and Broken Wires Outside Splice Opening

Figure 5 – Deteriorated Conductor Examined in the Kinectrics Study

Along with conductor replacement, HOSSM will replace the structures along the length of the line, which are largely in Poor, Very Poor and Fair condition as per the findings of the METSCO 2018 Asset Condition Assessment Study (see ISD# SR-01 for justification of the structure replacement program). The structures will be replaced with composite fibreglass equivalents (costs are included in the overall project estimate).

Alternatives:

Alternative #1: Do Nothing:

This is not an acceptable alternative as there are potential public and employee safety concerns. The conductor currently does not perform for its rated condition, meaning that HOSSM cannot utilize the line as contemplated until the issue is resolved. By not replacing the conductor, reliability to distribution customers connected at Batchawana and Goulais TS is materially reduced. Furthermore, a forced or planned outage of the K24G line would result in the dependence on the Sault #3 Line as a single contingency for a significant portion of HOSSM customers. Moreover, the deteriorated structures along the line present a failure risk that will continue increasing if left unaddressed.

As part of this option, HOSSM would continue with the strategy of reactive replacement of conductor and pole structures as portions fail. Given the logistical requirements associated with the reconductoring work, including staging, equipment and labour force availability, and outage feasibility, this is not an economic option for HOSSM's service territory nor is it desirable for customers.

Alternative #2: Proactive Replacement of Conductor with the New Equivalent and Wood Structures with Composite Units.

This is the recommended alternative, which is supported by both METSCO and Kinectrics external work and is seen as the only feasible option to address the equipment-related reliability issues experienced on the circuit over the past five years.

Investment Description:

Approximately 70 km of 115 kV line with Poor health conductor will be replaced in the section of the line between MacKay TS and Batchawana TS. Reconductoring operations will be taken as an opportunity to review the structures in the same section. Where required, structures with poor condition will be replaced by new ones, clearance violations will be fixed by increasing the height of the associated structures and unnecessary structures will be eliminated by consolidation of two adjacent structures.

During the construction period, Batchawana and Goulais stations will be fed from Third Line TS only, and the 230 kV K24G line will be the only north-south tie in the HOSSM system. Batchawana and Goulais station loads may be subjected to longer outage periods during the construction period as they will have one source only. After the project, HOSSM expects a significant performance improvement on the circuit.

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	$0.3	$3.0	$7.0	$7.0	-	-	-	-	-	$17.3

Investment Results and RRF Outcomes:

Customer Focus	• Improves reliability on the worst-performing circuit on the HOSSM system with the history of prolonged equipment-related outages.
Operational Effectiveness	• Enhances system operability by rectifying equipment issues on one of the most critical HOSSM circuits, enabling it to be operated under to the normal rating.
	• Reduces the risk of reactive repairs on a long critical circuit.

Investment Summary Document – System Renewal

SR-03 THIRD LINE TS TRANSFORMER REPLACEMENT

Start Date:	Q1 2021	**Priority:**	High
In-Service Date:	Q4 2023	**Total Cost ($M)**	4.8
Trigger(s):	Asset Condition, Reliability Risk, Safety		
Outcomes:	Operational Effectiveness, System Renewal		

Objective:

Proactively replace the 150/200/250 MVA 230/115/34.5kV T2 autotransformer equipped with an Under Load Tap Changer at Third Line TS, which is approaching Poor condition. This will ensure continued reliability of supply at HOSSM's station that supports the majority of customer load.

Need:

At the time of planned replacement date, transformer T2 will be 51 years old, which is approximately the end of its expected service life. In case of a failure of the unit, the station will be subject to single contingency through T1, the loss of which would result in extensive service outages in the Sault Ste. Marie area. Given the current system configuration, the timeline for rectification of a dual failure will be equal to the lead time of new unit, which is a minimum of 12 months. Based on METSCO's 2018 Asset Condition Assessment study, the unit's condition is calculated to be 51% (Fair, approaching Poor) as elaborated on in the Appendix B (METSCO Asset Condition Assessment Report). Given that Third Line TS supports the majority of load on the HOSSM system, maintaining service continuity and reliability of supply is critical for HOSSM to fulfill its service obligations.

Figure 6 – Third Line TS T2 Unit

Alternatives:

Alternative #1: Do Nothing

Failing to act will perpetuate the likelihood of an unplanned (emergency) T2 replacement need by way of failure in the field. This will expose the station and system to major service reliability risks for an extended period. Deferring the investment beyond the Plan period would result in a unit that would be nearly 60 years of age and in Poor condition presenting an unacceptable risk of failure to a critical asset on the system. Therefore Alternative #1 is not recommended.

Alternative #2: Refurbish the Unit to Prolong Service Life

Refurbishing the unit would involve taking it out of service for an extensive period of time, leaving Third Line TS operating on a single contingency. Moreover, given the units overall condition and advanced age (which is a proxy for deterioration of many internal parts that cannot be reliably assessed through non-destructive testing); the cost of transformer overhaul would be prohibitive in light of the moderate life extension that an overhaul may enable. On balance, this alternative is not recommended from both the economic and operational standpoints.

Alternative #3: Replace the T2 Unit with an Equivalent Transformer

This is the recommended alternative as it results in replacement of the oldest, and most deteriorated (on the basis of Health Index score) transformer in the HOSSM fleet. Proactive replacement will enable a comparatively quick installation timeline relative to the overhaul option, limiting the risk associated with the T1 unit operating on a single contingency basis.

Investment Description:

A new unit will be installed on a new pad with oil spill containment. Additional conductor/bussing, connectors, fencing, grounding, and civil support structure will need to be constructed to support the new transformer and the ancillary equipment. Until the new unit is commissioned, T1 will be the sole source of 230/115 kV to the HOSSM system from the Hydro One grid at Third Line station.

Given the criticality of the Third Line TS to the operation of both HOSSM's bulk system assets and the downstream load that the station serves, the transformer unit required is of a significantly larger capacity and technical rating materially different from most other HOSSM transformers. For instance, the replacement transformer's power rating

(250MVA) is substantially larger than the 40MVA-rated unit required at Northern Avenue (ISD SR-04), resulting in a materially higher replacement cost, as a result of the unit itself, along with the requisite installation work for the foundation, support, bussing and other elements.

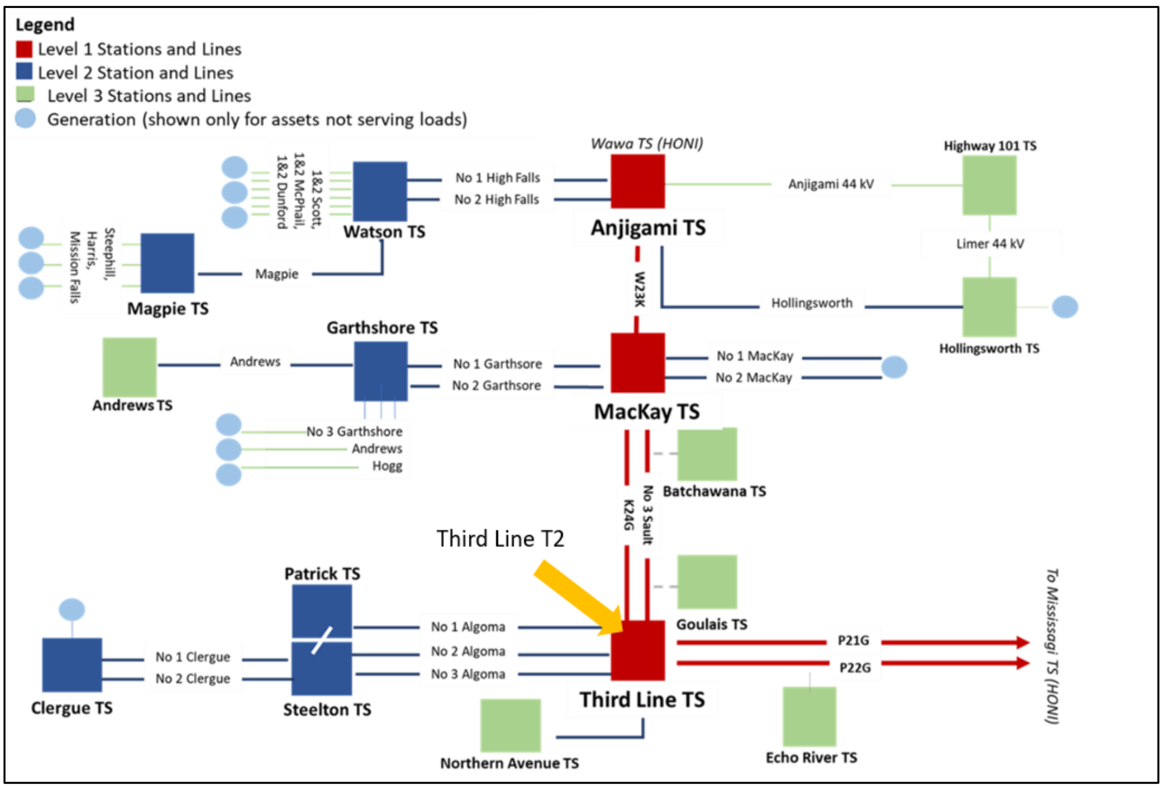


Figure 7 - Third Line T2 in the Context of System Operation

Project Costs:

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Capital Expenditures ($M)	-	-	-	$0.9	$1.7	$2.3	-	-	-	$4.8

**Numbers may not add up due to rounding*

Investment Results and RRF Outcomes:

Customer Focus	• Replaces a unit in deteriorating condition deployed at a critical load serving station.
Operational Effectiveness	• Ensures continued reliability and operability of a core bulk system asset.
	• Mitigates safety risks associated with equipment failure.

Investment Summary Document – System Renewal

SR-04 NORTHERN AVENUE TS TRANSFORMER REPLACEMENT

Start Date:	Q1 2023	**Priority:**	Medium
In-Service Date:	Q4 2024	**Total Cost ($M)**	1.4
Trigger(s):	Asset Condition, Reliability Risk, Safety		
Outcomes:	Operational Effectiveness, System Renewal		

Objective:

Planned replacement of the existing 20/26.7 MVA 115/34.5 kV T1 transformer that is in deteriorating condition.

Need:

At the time of the planned replacement date, transformer T1 will be 46 years old; around the end of its expected service life. In case of a failure of the unit, the station would lose its only 115 kV supply and would not be able to feed the downstream distribution loads. This exposure time would be equal to the lead time of a new unit which is minimum 12 months. Transformer T1's condition is calculated as 62% (Fair) in the METSCO Asset Condition Assessment Study and is expected to continue to deteriorate to a Poor or Very Poor Health Index rating over the seven years preceding the proposed replacement.

Figure 8 – Northern Avenue TS Transformer T1 Unit

Alternatives:

Alternative #1: Do Nothing

With the increasing age of the unit, doing nothing will further increase the likelihood of an emergency transformer replacement, which will expose the station and system to major service reliability risks for an extended period. This is amplified by the fact that T1 is the only 115 kV supply unit at the station, the failure of which would make the remaining 34.5 kV transformer without supply given the connection configuration. Therefore, Alternative #1 is not recommended.

Alternative #2: Refurbish the Unit to Extend Service Life

Refurbishment is not an advisable option. Doing so would involve taking the T1 unit out of service for an extended period of time, which is not practical given the capacity of the other transformer at the station. This would result in material reliability risk for the area supplied by the station. Moreover, refurbishment would only extend service life by a relatively short period of time, compared to an outright replacement.

Alternative #3: Replace the Unit with a New Equivalent Transformer

This is the recommended alternative that provides the optimal value for improving reliability of the station and renewing the overall health of the HOSSM system. The relatively quick outage required to bring the replacement unit online, compared to one required to complete a refurbishment would limit the reliability risk to the downstream load.

Investment Description:

A new identical or equivalent unit will be ordered and installed on a new pad with oil spill containment. Construction will take place during low load season and distribution loads will be served by alternative supplies during construction.

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	-	-	-	-	-	$0.4	$1.0	-	-	$1.4

Investment Results and RRF Outcomes:

Customer Focus	• Reduce the risk of lengthy equipment outages affecting downstream customer supply in the most densely populated area of the system.
Operational Effectiveness	• Mitigates the risk of safety concerns with failed or defective assets.
	• Improves the reliability and overall asset health of the transformer population.

Investment Summary Document – System Renewal

SR-05 WATSON TS INFRASTRUCTURE UPGRADES

Start Date:	Q1 2024	**Priority:**	Medium
In-Service Date:	Q4 2025	**Total Cost ($M)**	4.7
Trigger(s):	Asset Condition, Reliability Risk, Safety		
Outcomes:	Operational Effectiveness, System Renewal		

Objective:

Replace obsolete metalclad switchgear in deteriorated operating condition and with known mechanical issues with an equivalent replacement unit built to contemporary design standards that incorporates arc flash-rated safety features. Upgrade the station's bus arrangement to a three-breaker "ring" structure from the current arrangement, to improve operating efficiency and flexibility for the station.

Need:

The existing 34.5 kV metalclad switchgear in Watson TS is an obsolete model, nearing the end of its life. Currently, the station has an obsolete 34.5 kV vacuum circuit breaker metalclad line up, which transforms the generation of three power plants: Dunford GS, Scott GS and McPhail GS and serves two local lines in the Wawa district. Due its age, the switchgear requires frequent maintenance, mostly due to mechanical issues.

Breakers have had ongoing alignment issues. This results in higher than necessary maintenance expenditures. The switchgear unit is not arc-flash rated and as such, poses a risk to workers during switching and maintenance activities. Individual breakers in the switchgear currently have slightly varying health indices between 72% and 74%, which is expected to further deteriorate until the proposed time of replacement. It should be noted that breakers are only one of the many components of the switchgear assembly and as such do not adequately reflect the overall condition of the entire assembly, which in the case of the Watson TS units has had known issues with the racking mechanism that cannot be resolved by way of incremental repairs.

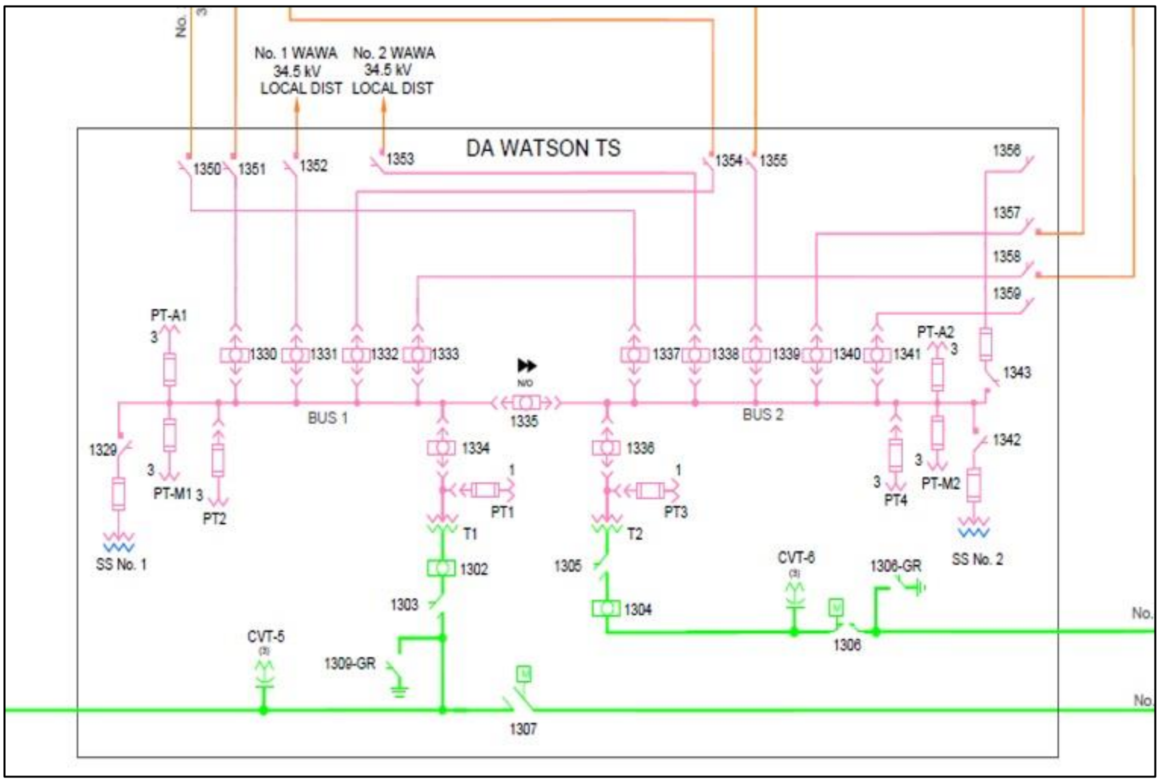


Figure 9 – Watson TS Single Line Diagram

In process of undertaking the replacement work, HOSSM also proposes to upgrade the bus arrangement to a more flexible three-breaker "ring" structure which would provide for improved operational flexibility of the asset. As shown on Figure 9, the station currently has two 115 kV breakers, each connecting a line to a transformer. One of the lines is a T-tap connection; effectively one of the breakers is connecting 2 segments of lines to one transformer. During a fault condition isolating a segment of the line while maintaining the other segment is not possible due to the current configuration. The proposed bus modification proposes to remove this operational limitation thereby improving reliability.

Alternatives:

Alternative #1: "Do Nothing"

The "Do Nothing" alterative maintains use of the obsolete product increasing reliability risk and prolongs the current safety risks associated with operating an obsolete unit not rated for arc flash safety, and prone to known mechanical issues. The option also implies a continued status quo for the bus arrangement, which limits the station's operational flexibility. This alternative is not advised as it does not resolve any of the issues underlying the project proposal.

Alternative #2: Replace the Metalclad Switchgear Unit Alone

Replacement of the metalclad unit as recommended is the only feasible alternative to address the issues which the investment seeks to resolve, including the removal of an obsolete unit not fully rated for contemporary safety best practices, among other issues noted above. While this could be a viable strategy absent the need for other work, the outages and construction activities on site create a viable opportunity make the additional modifications (i.e. the 115 kV ring bus configuration) proposed in the scope of the project.

Alternative #3: Replace the Switchgear Unit and Implement a 115 kV Ring Bus Arrangement

This is the recommended alternative that capitalizes on the construction work and outages to replace the switchgear by changing the breaker arrangement at the station, increasing the project's overall benefits by improving the station's operational flexibility.

Investment Description:

Based on Alternative #3, replace the existing metalclad switchgear with its modern equivalent that meets current safety standards. Replacement will be staged to minimize the disruption to service and limit the impact on customers.

Station is proposed to be converted to a 5-breaker ring bus by adding 3 more breakers; two feeders for transformers T1 and T2, and 3 feeders for 115 kV Magpie, 115 kV No. 1 High Falls and 115 kV No.2 High Falls lines.

Project Costs:

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Capital Expenditures ($M)	-	-	-	-	-	-	$1.0	$3.7	-	$4.7

Investment Results and RRF Outcomes:

Customer Focus	• Allows for more flexibility to perform maintenance on equipment without subjecting customers to an interruption;
	• Does not bottle all generation on a first contingency basis;
	• Newer switchgear less chance of failure therefore improved reliability;
Financial Performance	• Newer switchgear requires less maintenance;
	• Some elements are considered obsolete and therefore parts availability can be an issue.
Safety	• Will bring equipment up to current safety standards (i.e. arc flash-rated).

Investment Summary Document – System Renewal

SR-06 CLERGUE TS SWITCHGEAR REPLACEMENT AND CIVIL INFRASTRUCTURE UPGRADE

Start Date:	Q1 2025	**Priority:**	Medium
In-Service Date:	Q4 2026	**Total Cost ($M)**	4.8
Trigger(s):	Asset Condition, Reliability Risk, Safety		
Outcomes:	Operational Effectiveness, System Renewal		

Objective:

To replace an obsolete metalclad switchgear with an equivalent replacement unit built to meet current industry standards such as arc flash-rated safety features, and perform upgrades to the station's civil infrastructure, including fencing, and drainage and gravel in the station yard.

Need:

Clergue TS connects the Clergue Generating station and LSP co-generation stations to HOSSM grid via two 115 kV lines going to Steelton TS. The existing 12 kV indoor metalclad switchgear at Clergue TS is an obsolete product near the end of its useful life. Switchgear is not arc-flash rated and is posing a safety risk to workers during switching and maintenance operations. Individual condition of the breakers of the metalclad switchgear varies from 72% to 74% (Good).

These breakers are oil type, which are themselves increasingly considered obsolete in the industry. It should be noted that, the condition of the breakers represents only a portion of the switchgear's overall condition and should not be used as a proxy for its overall condition and operating state. Aside from the lack of arc flash protection, the unit's obsolescence is also based on the fact that the manufacturer of the switchgear is no longer in business, making procurement of any replacement parts increasingly difficult.

In addition, to breaker replacement work, HOSSM intends to leverage the project resources on site to undertake upgrades to the civil components of the station, such as fencing to ensure security of access and the gravel bed and drainage to ensure proper grounding.

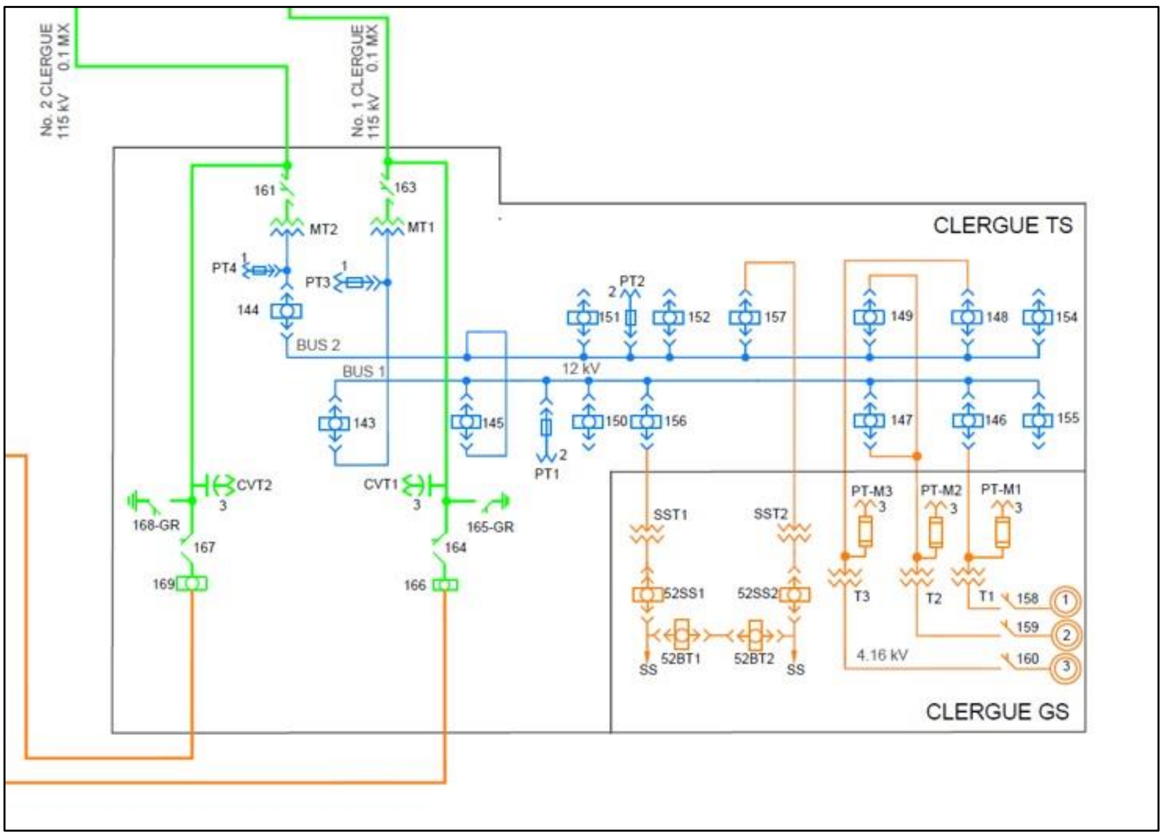


Figure 10 ‑ Clergue TS Single Line Diagram

Alternatives:

Alternative #1: Do Nothing

The “Do Nothing” alterative prolongs the current status quo of operating an obsolete unit not rated for arc flash safety, exposing personnel conducting maintenance and switching work to potential safety risks. This option is not advised as it does not resolve any of the issues inherent in the project need.

Alternative #2: Replace the Switchgear Unit

Replacing the unit as per the recommended option is the only feasible alternative to address the issues which this investment seeks to resolve, as refurbishment would not address the obsolescence and safety issues that underlie the need. .

Investment Description:

HOSSM proposes to replace the existing switchgear with its modern equivalent which is arc-flash proof, featuring vacuum or SF6 type breakers in arc-resistant metalclad switchgear. The current unit is made up of two separate line ups in the same room. New units can be installed one line up at a time to ensure continuity of the service. Removed units can be salvaged for parts. Also included in the investment is the replacement of fencing and grounding, drainage and crushed rock for the yard, all of which can be done while the station is in service to limit the scheduled outage duration.

Project Costs:

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Capital Expenditures ($M)								$1.0	$3.8	$4.8

Investment Results and RRF Outcomes:

Financial Performance	• Newer switchgear requires less maintenance;
	• Some elements are considered obsolete, making procurement of replacement part a complex and costly matter.
Safety	• Will bring equipment up to current safety standards (i.e. arc flash-rated).

Investment Summary Document – System Renewal

SR-07 ECHO RIVER TS CIRCUIT BREAKER REPLACEMENT

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Q4 2020	**Total Cost ($M)**	1.0
Trigger(s):	Asset Condition, Reliability Risk		
Outcomes:	Reliability Risk Mitigation, System Renewal		

Objective:

Enhance supply reliability at Echo River TS, by replacing the degraded single high-side 230kV circuit breaker.

Need:

Service continuity of distribution load connected to Echo River TS depends on a single 230kV high side minimum oil circuit breaker. During extended failure or maintenance of this asset, distribution load restoration involves extending back up through a medium-voltage feeder from Northern Avenue TS, causing voltage fluctuations due to length of the feed, and increasing the strain on the backup source.

The Health index of the existing Circuit Breaker 556 is calculated to be 50% (Fair, nearing Poor). Given the deteriorating condition of the original asset, the need for a replacement unit is further amplified. Furthermore, the current asset is a live tank minimum oil breaker, which HOSSM has indicated is considered an obsolete type and due for replacement when practicable.

Figure 11 – CB 556 Minimum Oil Breaker at Echo River TS

Alternatives:

Alternative #1: Do Nothing:

This would expose the Echo River TS area distribution loads to relying on a single deteriorating breaker during the winter peak periods. An asset failure during this time would require the initiation of rotational load shedding to supply the area. Moreover, the existing breaker unit is in Fair condition, meaning that its probability of failure will only become elevated over time. Based on these considerations, Alternative #1 is not recommended.

Alternative #2: Maintain and Refurbish the Asset:

The asset model is an ASEA HLR 245, which is no longer supported by the manufacturer. The circuit breaker requires oil changes during each inspection and has recently had its gaskets and O-rings replaced. Based on the advanced age, type, and deteriorating condition of this asset, maintenance costs are becoming more frequent and expensive. Maintenance on this unit also requires complete disconnection of the Echo River No. 1 and No. 2 local distribution feeders, resulting in outages to the associated customers. Based on these otherwise avoidable costs, and the fact that the unit's design is obsolete, Alternative 2 is not recommended.

Alternative #3: Procure a new 230kV SF6 Breaker

This is the recommended alternative, as it provides a new unit that will significantly reduce maintenance cost and frequency. Moreover, procurement of a dead tank SF6 breaker removes obsolescence concerns for this asset. Planned procurement and installation of the new asset further reduces impact to customers.

Investment Description:

A new dead tank SF6 230 kV circuit breaker will be purchased. Old supports will be removed, and new foundation will be constructed for the breaker. Construction work will be performed during the low load season such that loads can be served via Northern Ave TS supply.

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	-	-	$1.0	-	-	-	-	-	-	$1.0

Investment Results and RRF Outcomes:

Operational Effectiveness	• Addresses a vulnerable point on the system currently served by a unit in deteriorating condition.
	• Improves system operability and reduces maintenance requirements through elimination of an obsolete technology.
Customer Focus	• Helps maintain service continuity at a load serving station with limited available contingencies.

Investment Summary Document – System Renewal

SR-08 STEELTON TS BREAKER UPGRADE

Start Date:	Q1 2022	**Priority:**	Medium
In-Service Date:	Q4 2024	**Total Cost ($M)**	2.3
Trigger(s):	Asset Condition, Reliability Risk, Safety		
Outcomes:	Operational Effectiveness, Safety, System Renewal		

Objective:

Proactively replace the existing 115 kV breaker and disconnect switch assets at Steelton TS with new units to reduce outage risk, enable safe clearance distances and retire obsolete equipment approaching the threshold of a "Poor" rating.

Need:

There are four Minimum Oil Live Tank circuit breakers (units 208, 211, 214 and 217) in operation at Steelton TS. The units are technologically obsolete due to the lack of spare parts and manufacturer support. The current physical arrangement of the breakers presents safety clearance problems, particularly in the winter months, where snow accumulation volumes prevent HOSSM staff from observing minimum encroachment distances during regular or reactive maintenance operations.

The circuit breakers in question have been calculated to have current Health Indices between 61% and 63% (Fair condition) and are all 1981 vintage. At the time of their planned replacement these breakers already deemed to be obsolete, will be 41 years old and are expected to have deteriorated into the Poor condition health index. Breaker disconnect switches supporting the units have required increasingly frequent servicing in recent past due to mechanical alignment issues. The units' continuous current rating is also below the operational requirements during contingency events. Present bus layout and clearances prohibit the maintenance of disconnect switches without obtaining extensive outages at the station, leading to increased maintenance expenditures and downtime and increased reliability risk for the customer connected to the station including a large industrial facility that is highly sensitive to frequency of outages. The disconnect switches in question are 2003 vintage. The Health Index is calculated as Very Good for these units. However, this assessment is based on a limited amount of visual inspection information, and in HOSSM's experience does not reflect the mechanical performance of the units, which is the key reason for replacing the switches along with the degraded and obsolete breakers.

Figure 16 – Existing Minimum Oil Circuit Breaker 214 at Steelton TS

Alternatives:

Alternative #1: Do Nothing

Failure to act prolongs the existence of safety clearance issues and the obsolete, deteriorating units remain in service. This presents an ongoing reliability risk and higher maintenance expenditures in lieu of more frequent disconnect switch maintenance requirements than would otherwise be necessary. This is particularly notable given the industrial customer's sensitivity to service disruptions. Therefore this alternative is not recommended.

Alternative #2: Replace Breakers Only

This option reduces the estimated project cost by approximately 10% through reduced scope of labour and equipment by keeping the existing switches intact in light of their better condition rating than the Breakers. However, as noted previously, notwithstanding their rated condition as per the METSCO study, the switch units proposed for replacement are characterized by persistent operational issues during maintenance, which do not lend themselves to consistent capturing by way of systemic condition assessments at the asset class level.

Given the relatively small portion of savings this scope reduction would yield, and given the fact that combining the work would reduce the aggregate impact of requisite outages, this alternative is not recommended.

Alternative #3: Replace Breakers and Switches

This is the recommended alternative, which includes the combined replacement of breaker and switch units. This alternative addresses all the safety and reliability issues underlying the project need, while enabling maintenance savings in the form of reduced frequency of serving breakers with contemporary technology, and reduced need for costly outages.

Investment Description:

The project scope entails installing new SF6 dead tank circuit breakers in place of existing ones, complete with new breaker disconnect switches. Breakers will be installed on new foundations with platforms high enough to clear snow accumulation in the station for personnel safety and ease of operation. In order to minimize the disruption to service, breakers and disconnect switches will be installed one bay at a time. Use of dead tank breakers will eliminate the need for existing self-standing current transformers.

Project Costs:

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Capital Expenditures ($M)	-	-	-	-	$0.2	$1.0	$1.2	-	-	$2.3

**numbers may not add up due to rounding*

Investment Results and RRF Outcomes:

Operational Effectiveness	• Replaces obsolete equipment requiring additional maintenance and no longer supported by the manufacturer.
	• Facilitates more efficient maintenance operations through an improved bus structure design.
Customer Focus	• Reduces the risk of lengthy equipment outages.

Investment Summary Document – System Service

SS-01 NEW GREENFIELD TS

Start Date:	Q1 2019	**Priority:**	High
In-Service Date:	Q4 2022	**Total Cost ($M)**	11.1
Trigger(s):	Asset Condition, Reliability Risk, Safety		
Outcomes:	Operational Effectiveness, System Renewal		

Objective:

To consolidate the assets of two nearby stations, each with one operational power transformer in or approaching Fair condition, into a single station equipped with two new power transformers and other renewed station assets. This will address safety clearance issues during certain operating conditions, and enhance operational efficiency by enabling station maintenance without customer outages.

Need:

Existing equipment at the neighbouring Goulais and Batchawana TS is in deteriorated condition as per the METSCO ACA and staff inspections and requires replacement. Transformers at both stations are protected by fuses, often tripping due to downstream faults and causing outages to customers that require staff to be dispatched to replace the fuses manually adding to the length of interruption. Other specific station assets require a customer interruption to perform routine maintenance.

The 115 kV disconnect switches exceed their continuous current rating when the 230/115 kV transformer trips at MacKay station. Stations require additional equipment maintenance to be able to operate the stations in a reliable manner.

Both stations have one transformer connected as the single source of supply, failure of which presents significant reliability risks. HOSSM notes that a total of three “spare” power transformers removed from operation elsewhere in the past are maintained on station grounds (two at Goulais and one at Batchawana). However, none of these units are connected to the system, and their Health Indices as per the METSCO ACA are between 52% and 67%, representing a significant degree of deterioration.

The battery, charger and remote terminal units at both stations have no redundancies, are contained within outdoor enclosures and are obsolete given the lack of spares and discontinued commercial availability. Ancillary equipment malfunctions have caused a number of nuisance alarms in poor weather conditions in the recent past. Both stations are built on sloping grounds; clay and rock bottom are making it difficult to provide appropriate drainage. Importantly, due to historical design issues, both stations have insufficient working clearances which necessitate the use of temporary fencing during certain maintenance operations.

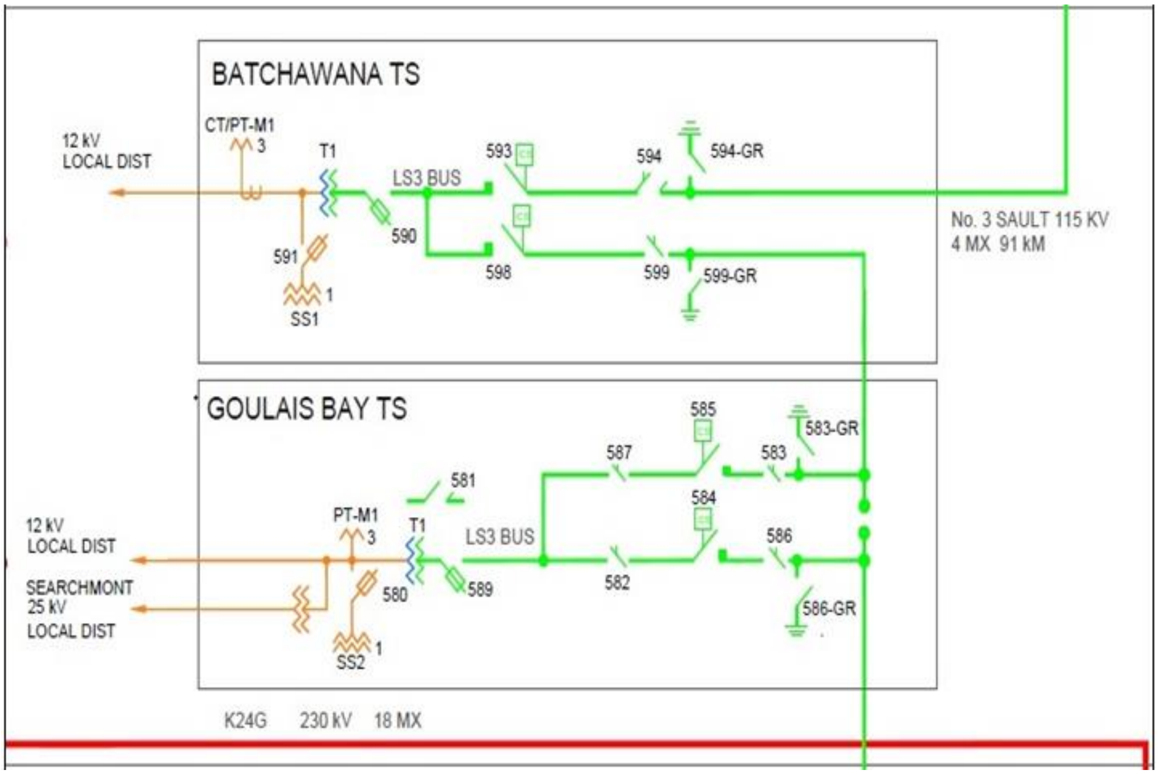


Figure 12 – Goulais and Batchawana TS Single Line Diagrams

Figure 13 – Batchawana TS

Figure 14 – Goulais TS

During winter conditions, snow accumulation above three feet, which is common for the area, presents a safety issue due to the low clearance of lines exiting the Goulais TS in particular, creating further safety risks for staff performing work in the area.

Figure 15 – Evidence of Extensive Transformer Oil Leaking at Goulais TS

In addition to the above-noted drivers, the consolidation of station assets carries potential benefits in the form of reduced average maintenance expenditures as the assets formerly located at two separate sites could be serviced at once, without requiring scheduled outages, as well as capital equipment efficiencies in the form of lower expenditures for common station infrastructure.

Alternatives:

Alternative #1: "Do Nothing"

The "Do Nothing" alternative will allow further the deterioration of the equipment condition over time, thereby increasing the probability and potential severity of outages. Without intervention, these assets will have a negative impact on the supply to customers and reliability of the system. Both stations supply customers using single transformer units without reliable means to procure spare parts. The physical location of the stations will also impede restoration efforts, especially during adverse weather conditions. Furthermore, both stations have insufficient clearances and pose a high risk to maintenance personnel. This further exacerbates the time it takes to recover the system from an outage. In sum, doing nothing is not a recommended alternative, as it represents the continuation of present trends, which carry substantial safety and reliability risks.

Alternative #2: Replace aging transformers and other equipment at the individual locations.

Issues regarding this alternative include the lack of available space surrounding the existing station sites will not facilitate the installation of new assets while equipment remains in service, ground conditions cannot be improved sufficiently enough to address the site drainage issues and this alternative still will not address that the supply to customers will still hinge on a single source of power with one transformer connection that can result in an interruption on a first contingency basis. Based on these considerations, this alternative is not recommended.

Alternative #3: Build a consolidated new station served by a single transformer.

This alternative reduces the total amount of equipment to be maintained, and reduces the number of locations from two to one, thus reducing operation and maintenance costs in the future. However, the station would now have one transformer for two distribution connections; further exacerbating the impact of transformer contingency. Based on high risk of customer outage, this option is not recommended.

Alternative #4: Build new station with two transformers.

In addition to the advantages of alternative #3 above, with the addition of a second transformer, this alternative ensures a more reliable source of supply to both distribution connections.

Investment Description:

A new 115/25 kV station will be built at a location between existing Batchawana and Goulais stations. The new station will employ a three-breaker (pi configuration) scheme to connect Sault #3 Line 115 kV circuit to the two transformers. The station will be equipped with modern protection, control and communication equipment. This configuration will allow the station to be fed from either of the MacKay or Third Line stations in case of a fault on Sault #3 Line. The current distribution network in the area is 12 kV. The new station will operate at 12 kV until Algoma Power Inc. (the downstream distribution company) upgrades their network to 25 kV.

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	-	$1.0	$2.4	$2.5	$5.3	-	-	-	-	$11.1

**numbers may not add due to rounding*

Investment Results and RRF Outcomes:

Customer Focus	• Improves local area reliability by addressing two locations with extensive equipment condition deterioration issues.
Operational Effectiveness	• Provides opportunities maintenance savings through, reducing travel requirements for proactive and reactive maintenance combining maintenance activities and simplifying outage coordination for maintenance work.
	• Enhances Employee Safety by addressing historical issues with equipment clearances that could not be addressed at the legacy sites.
Financial Performance	• Introduces opportunities for capital asset consolidation by leveraging ability to deploy common station infrastructure at a single location instead of having two sets of similar equipment at two discrete locations.

Investment Summary Document – System Service

SS-02 STEELTON TS DISCONNECT UPGRADE

Start Date:	Q1 2025	**Priority:**	Low
In-Service Date:	Q4 2026	**Total Cost ($M)**	0.6
Trigger(s):	System Configuration		
Outcomes:	Operational Effectiveness		

Objective:

To increase the operational flexibility of the Steelton TS by adding line disconnect switches to the Steelton TS ring bus structure.

Need:

Steelton TS employs a six-breaker ring bus configuration. Two of the feeders are directly feeding Patrick St. TS ring, while the remaining four feed the 115 kV Number 1 and Number 2 Clergue lines and Number 2 and Number 3 Algoma lines. In order to maintain the integrity of the ring bus, motorized line disconnect switches need to be utilized so that a line fault on any of these lines can be isolated from the system without having to leave additional assets out of service until the tripped line is re-energized. Addition of the line disconnect switches would also simplify the maintenance procedures in the station where obtaining outage permits from customers is very difficult. Furthermore, Steelton TS breakers are at risk of destructive surges from lines while they are in open position for long periods of time. The addition of line disconnect switches would eliminate this risk completely.

Alternatives:

Alternative #1: "Do Nothing"

The "Do Nothing" alternative will prolong the current condition where the integrity of the ring bus is compromised each time a line is tripped and not reclosed due to a permanent fault. This can result in damage to the assets. Therefore this alternative is not recommended.

Alternative #2: Complete Installation of Disconnect Switches

This is the recommended alternative as it delivers the benefits sought by way of addition of line disconnect switches to the existing bus structure allowing appropriate isolation of faulted equipment from the system without exposing additional equipment to fault current surges.

Investment Description:

New motorized air break line disconnect switches will be installed on 115 kV No. 1 and No. 2 Clergue lines and No. 2 and No. 3 Algoma lines. The installation of these switches will be done during the proposed replacement of the oil circuit breakers to minimize construction costs and outage requirements. To maintain maximum possible uptime, installation of line disconnect switches will be done in a staged manner, one bay at a time.

Project Costs:

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Capital Expenditures ($M)	-	-	-	-	-	-	-	$0.3	$0.3	$0.6

Investment Results and RRF Outcomes:

Operational Effectiveness	• Reduces requirements for scheduled outages to complete maintenance work
	• Increases operational flexibility of the system by augmenting station equipment configuration.
Customer Focus	• Reduces the need for equipment outages on an asset connecting a key industrial customer who is highly sensitive to service interruptions.

Investment Summary Document – System Service

SS-03 STATION PROTECTION UPGRADE PROGRAM

Start Date:	Q1 2019	**Priority:**	High
In-Service Date:	Q4 2023	**Total Cost ($M)**	2.1
Trigger(s):	Reliability, Operating Efficiency, System Interoperability		
Outcomes:	Operational Effectiveness		

Objective:

Replace and upgrade technologically obsolete Protection Relays at Watson TS, Third Line TS, and Hollingsworth TS to maintain system reliability and operability.

Need:

The population of currently installed protection relays at the Watson, Third Line, and Hollingsworth stations are obsolete in terms of their design and continued vendor support (with a large portion represented by electromechanical relays) or have known operational issues or shortcomings in their protection and communication features. These deficiencies lead to additional maintenance expenditures due to periodic unnecessary trips, difficulties in procuring replacement parts that are no longer commercially available, or limits in the scope of available after-fault information, critical for ongoing system planning.

The majority of relays proposed for replacement are of electromechanical design, which has been considered obsolete for some time. Aside from commercial and technological obsolescence, HOSSM has experienced undesirable and costly operational issues due to periodic malfunctioning of this equipment during normal station operations. These issues include bus differential relays unnecessarily tripping during the switching of station service transformers, or voltage imbalance conditions that should not cause relay trips if the protection equipment operates as designed. In the case of stations that are distant from HOSSM's headquarters, the operation of electromechanical relays necessitates long crew dispatches to verify and rectify the issue causing the operation of protection mechanisms. In the events where relays operate without a sufficient reason, these crew dispatches amount to unnecessarily incurred reactive maintenance expenditures.

HOSSM's Relay Replacement program has been in place for the majority of the historical (2013-2017) period. The relays proposed for replacement over the Plan period are a continuation of this program.

Alternatives:

Alternative #1: "Do Nothing"

Doing nothing is not a recommended alternative, as it will cause HOSSM to further incur unnecessary reactive maintenance costs, while customers endure increased avoidable outages. More valuable station equipment will continue to be exposed to increased risk of damage due to the presence of protection equipment with known malfunction issues.

Alternative #2: Holding Replacement Units in Inventory to Replace Relay Units Reactively as they Fail, (as opposed to procuring them reactively after failure as would be required in the Alternative #1)

This option entails holding an inventory of replacement units on hand but only replacing particular units as they fail (to pace the underlying labour costs). This option is not recommended, since in the case of a reactive relay problem, an unplanned replacement may take substantial time due to limited availability of parts of the obsolete relay units, which are no longer supported by manufacturers. Delayed replacement may force the system to operate on a contingency basis for an extended period of time. Maintaining a substantial inventory of spare relays on hand is also not economical, since the current population in the station noted contains a number of various types (e.g. Alstom MFAC, Alstom KBCH 120, Alstom KCEG 140, Alstom KCEG 142, Alstom MCAG, Alstom MFAC, MiCOM 141, etc.). Given that there is no reliable way to determine which relays will fail when, and given the relatively modest installation labour costs, maintaining a significant inventory across various types for the purposes of reactive replacement is not economical.

Alternative #3: Proactively Replace the Relays

Proactively replacing the relays in the three stations over the course of a five-year period is the recommended alternative that addresses the operational efficiency, reliability and interoperability issues supporting the project need.

Investment Description:

Replace the existing relay units with contemporary equivalents. The estimated costs of the program per station are provided in the following table:

Station	Expenditures ($M)
Watson TS	$1.1
Hollingsworth TS	$0.5
Third Line TS	$0.5

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	$1.1	-	-	-	-	-	-	$1.0	-	$2.1

Investment Results and RRF Outcomes:

Operational Effectiveness	• Replaces obsolete equipment that is no longer supported by manufacturers and has been known to malfunction, leading to otherwise avoidable reactive expenditures.
	• Helps maintain interoperability of assets
Customer Focus	• Ensures reliability of service and avoidance of unnecessary interruptions for downstream distribution customers.

Investment Summary Document – System Service

SS-04 CONSOLIDATION CAPITAL AND MINOR FIXED ASSETS

Start Date:	Q2 2018	**Priority:**	Medium
In-Service Date:	Q4 2026	**Total Cost ($M)**	2.2
Trigger(s):	Safety, Efficiency, Internal Compliance		
Outcomes:	Operational Effectiveness		

Objective:

To facilitate the effective incorporation of HOSSM's asset base and its asset management function into the operations of Hydro One over the Plan period, and to ensure consistent application of standards, policies, and procedures of Hydro One across the operations of the HOSSM. Hydro One's practices involve a substantially greater rigour in the scope and nature of maintenance and investment planning and equipment testing activities.

Ensuring that these practices and standards are implemented across the HOSSM asset base in a consistent and economically responsible manner is expected to deliver material benefits by extending the lifecycles of HOSSM assets, delivering maintenance efficiencies over time, and promoting employee safety in the manner that meets Hydro One's enhanced corporate standards. In addition, this program targets repairs and replacements of all the smaller station assets as they reach the end of their useful life or become in a state disrepair. Among these assets are Capacitor Voltage Transformers ("CVTs"), Potential Transformers ("PTs"), Vented and Non-Vented Station Battery Banks, and other station service infrastructure, along with SCADA and Telecommunications equipment.

Need:

In the course of ongoing work to absorb and integrate HOSSM's system and the asset management function into Hydro One's operations, HOSSM and Hydro One asset management experts are in the process of identifying instances where the two companies' asset management standards and policies are not aligned. This program seeks to ensure the implementation of Hydro One's standards in the HOSSM territory in an economically responsible manner, by way of the following activities:

- Replacements or modifications to equipment that do not meet Hydro One's internal asset management policies or equipment standards (e.g. porcelain line insulators);
- Modifications to assets or purchases of equipment and implements to maintain compliance with Hydro One's employee health and safety regulations;
- Ongoing replacements of smaller-value station equipment as required by condition and normal operating practices (e.g. station batteries, instrument transformers);
- Procuring equipment, tools and implements required to undertake additional maintenance practices required by Hydro One that are expected to be adopted by HOSSM over the course of the transition period;
- SCADA, communications and other telemetry equipment requiring upgrades or installations at HOSSM facilities to meet Hydro One's operating practices and policies and
- Technical studies required to further assess the state of HOSSM plant, load flow patterns, or any opportunities to consolidate the equipment or operating practices at facilities where HOSSM and Hydro One equipment is located side-by-side (e.g. Mississagi and Wawa TS, among others).

This work is proposed for inclusion into this Plan's funding envelope in light of the anticipated benefits that the more rigorous asset management processes are expected to generate over time, including but not limited to equipment lifecycle extension, and reactive maintenance reduction.

Among the smaller station equipment analyzed in the course of the 2018 ACA performed by METSCO, a number of assets are reaching deteriorated condition that will warrant replacement over the Plan period, as showcased by Figures 17-19 below.

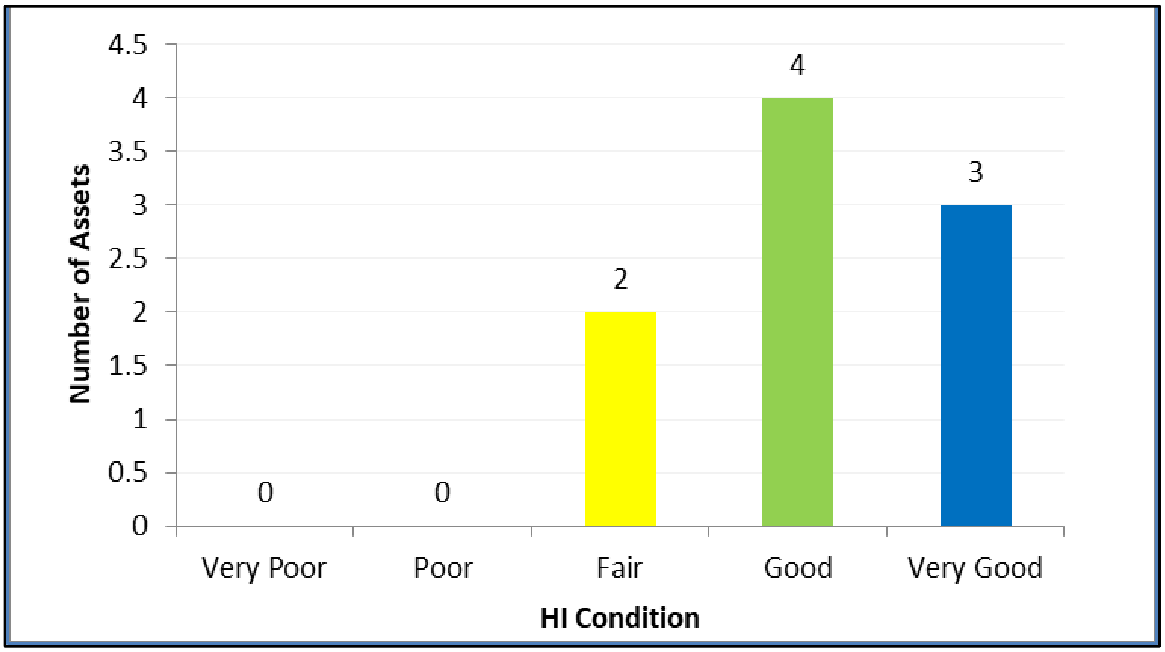


Figure 17 – Vented Battery Health Index

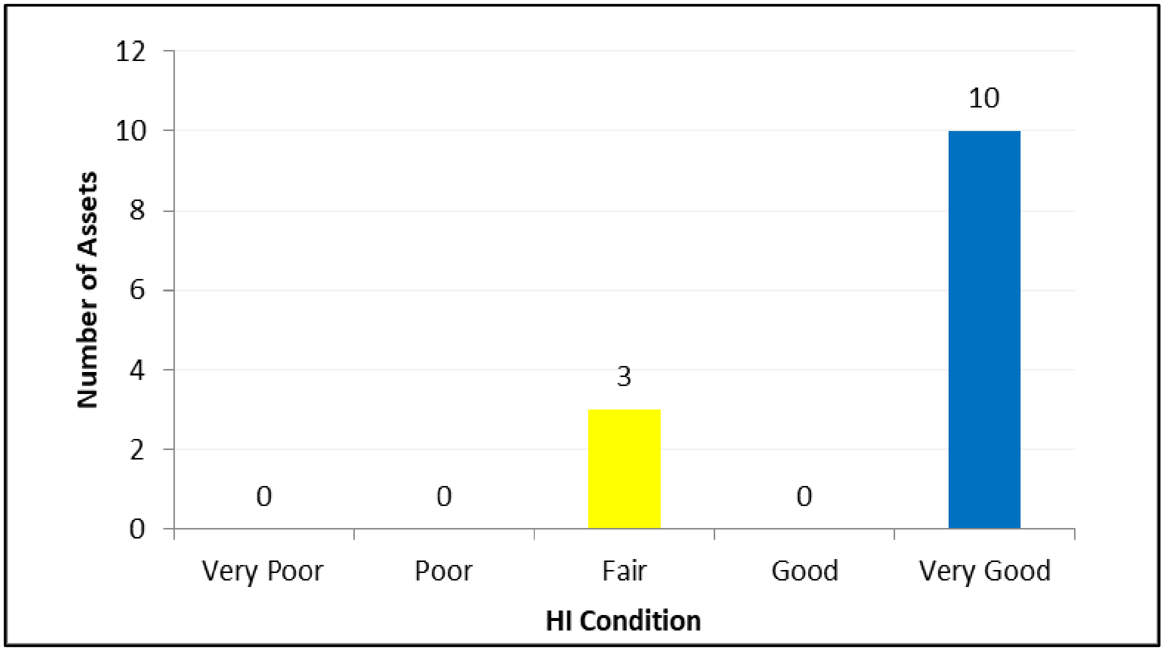


Figure 18 – Non-Vented Battery Health Index

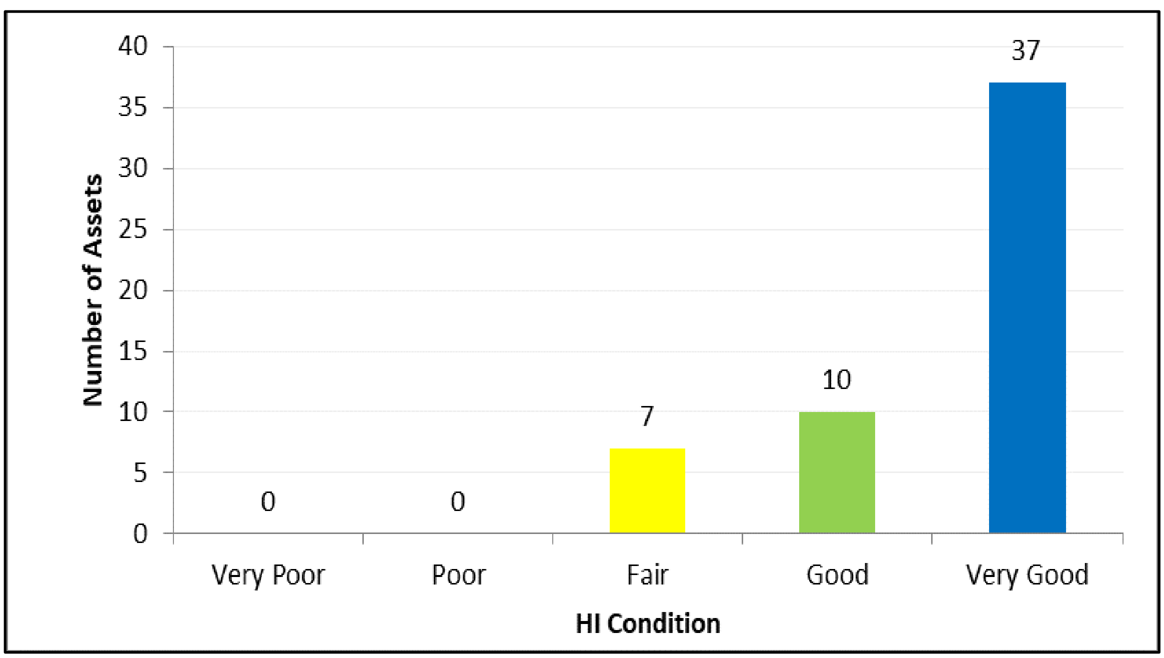


Figure 19 – Instrument Transformer Health Index

It is expected that a portion of these and other smaller station service assets, along with civil infrastructure (fences, concrete pads, oil spill containment areas, gravel etc.) will require replacement, modification or refurbishment over the Plan period. A portion of funding comprising this program is directed to complete some of this work.

Finally, as indicated in a number of other HOSSM ISDs related to station equipment, due to historical circumstances and the subsequent evolution of safety standards, a number of HOSSM station facilities do not meet the current safety clearance requirements as mandated by the Electrical Utility Safety Rules, Limits of Approach for Personnel and Equipment, Rule 129 due to spatial restrictions, configuration or seasonal weather phenomena (most notably snow accumulation). As the integration work progresses, all of these circumstances will be studied in more detail, and incorporated into the Capital Investment Plan to ensure all issues are addressed in the most appropriate manner to lessen any negative impact to customers.

Alternatives:

Alternative #1: "Do Nothing"

This alternative is not practical, as it would effectively amount to HOSSM system continually operating as a separate embedded entity within Hydro One's transmission system, with its own set of policies and standards, demanding separate system plans, procurement processes and other operational activities that would otherwise be consolidated. Given the relatively small size of the HOSSM system, maintaining its operation on its own set of standards is not economically feasible and inconsistent with Hydro One's policies. Moreover, doing nothing will lead to further deterioration and disrepair of small station equipment that is also included in the scope of this program. This would have adverse consequences on HOSSM's reliability, safety of its staff, and potentially risk damage to larger station equipment. Therefore this alternative is not recommended.

Alternative #2: Proceed with this program as Proposed

Although the scope and pacing of activities comprising this program will be determined on an ongoing basis, HOSSM believes that proceeding with this work without delay is the most responsible alternative, to ensure employee safety and continued reliability of the assets and accelerate the timeline for achieving the financial benefits expected from this work, through extension of asset lifecycles, progressive elimination of avoidable maintenance activities and others.

Investment Description:

Specific investments included in this program will be managed according to the internal work execution practices, and ARA and IPP processes discussed in this Plan (Sections 3.1.3.2 and 3.1.3.3). Using Hydro One's processes will ensure investments are identified, selected, and prioritized in a consistent and transparent manner against other investments. Any additional efficiency identified through the integration process will be incorporated into the ongoing Plan.

Project Costs:

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Capital Expenditures ($M)	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$2.2

**numbers may not add up due to rounding*

Investment Results and RRF Outcomes:

Operational Effectiveness	• Facilitates consolidation of equipment and materials standards to drive long-term capital and operation efficiencies through scale economies available to Hydro One, otherwise unattainable by the much smaller HOSSM.
	• Enables timely replacement of smaller equipment to maintain reliable system operation and promote consistency in operating practices across Ontario's transmission system.
Customer Focus	• Ensures provision of consistent level of customer service to transmission-connected customers throughout Ontario.
Public Policy Responsiveness	• Promotes incorporation of electrical safety and workplace safety best practices across Ontario's high-voltage electricity grid.

Investment Summary Document – General Plant

GP-01 GREENFIELD TS LAND PURCHASE

Start Date:	Q1 2019	**Priority:**	High
In-Service Date:	Q4 2019	**Total Cost ($M)**	2
Trigger(s):	Greenfield TS Construction		
Outcomes:	Operational Effectiveness		

Objective:

Purchase a suitable parcel of land to undertake the planned construction of the consolidated Greenfield TS (See ISD# SS-01) in the area North of Sault Ste. Marie along Highway 17, between the current locations of the Goulais and Batchawana Transformer Stations that the proposed project will replace.

Need:

To construct the Greenfield TS project (ISD# SS-01), HOSSM must secure a suitable parcel of land. At present, HOSSM does not own any suitable land parcels in the area.

Alternatives:

Alternative #1: "Do Nothing"

This alternative would prevent HOSSM from proceeding with the construction of Greenfield TS, as currently planned in this TSP and the ensuing delay of benefits and prolongation of risks associated with this project. This will continue to have a negative impact on customers. Therefore this alternative is not recommended.

Alternative #2: Lease a Land Parcel

Leasing land parcels for the expected lifetime of a new station (40-60 years, with potential subsequent extensions through equipment replacement) introduces substantial risks to HOSSM's lifetime cost of ownership and continued site access, should the land owner choose to modify the terms of the arrangement during its time. This alternative is not recommended.

Alternative #3: Acquire a Land Parcel

Acquisition of a suitable land parcel that will address all of the shortcomings of the current station (e.g. sloping grounds, spatial restrictions, etc.) is the recommended alternative for this project. Proceeding with these projects will have a positive impact on customers by improving reliability, operational efficiencies, and financial performance.

Investment Description:

Procure a suitable parcel of land one year ahead of construction activities to enable site preparation, measurement and staging work.

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	-	$2.0	-	-	-	-	-	-	-	$2.0

Investment Results and RRF Outcomes:

Operational Effectiveness	• Enables construction of a key System Service project set to provide a number of Operational and Reliability benefits.
	• Enables construction of a facility that meets all safety setback requirements.

Investment Summary Document – General Plant

GP-02 THIRD LINE TS STORAGE BUILDING

Start Date:	Q1 2019	**Priority:**	High
In-Service Date:	Q4 2019	**Total Cost ($M)**	0.8
Trigger(s):	Operating Needs, Inventory Management		
Outcomes:	Operational Effectiveness		

Objective:

Construct a permanent indoor environmentally controlled storage facility for HOSSM's population of spare and replacement parts, hand-held tools and equipment and winter transportation fleet (snowmobiles, trailers, etc.).

Need:

At present, HOSSM does not have access to an indoor storage facility where both larger and smaller equipment tools and replacement parts can be stored in an environmentally controlled manner. Instead, spares are often stored at various station sites, indoors in small transportation storage containers or outdoors, where they are exposed to the elements. This decentralized approach complicates inventory management for HOSSM and in some cases, results in a degree of degradation of spares before they are put into service. The site at Third Line TS, HOSSM's largest station, can accommodate a sufficiently large storage building to meet the anticipated needs for indoor storage.

Alternatives:

Alternative #1: "Do Nothing"

This alternative does not permit realization of benefits of consolidated and environmentally controlled facility sought by this project. Accordingly, this alternative is not recommended.

Alternative #2: Lease an Existing Storage Facility

This alternative does not account for the opportunity cost of unoccupied land at the Third Line TS site that HOSSM could use more productively, including a more central location and proximity to a key HOSSM station. Furthermore uncertainties exists surrounding long-term leasing arrangements in terms of pricing, facilities upkeep and liability insurance, among others. Therefore this alternative is not recommended.

Alternative #3: Construct a Permanent Facility

This is the recommended alternative for this investment, as it enables HOSSM to utilize the available and otherwise unoccupied real estate at Third Line TS to achieve the benefits targeted by the project.

Investment Description:

Construct a storage facility on the land adjacent to Third Line TS. The existing station grounds are sufficient to locate a new building while meeting all appropriate safety setbacks relative to the station's electric assets.

Project Costs:

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Capital Expenditures ($M)	-	$0.8	-	-	-	-	-	-	-	$0.8

Investment Results and RRF Outcomes:

Operational Effectiveness	• Improved inventory management practices for spares and tools.
	• Reduced exposure to elements of spare parts kept on site; and opportunity to perform certain repair tasks indoors during inclement weather.

Investment Summary Document – General Plant

GP-03 GENERAL PLANT RENEWAL PROGRAM

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Q4 2026	**Total Cost ($M)**	1.1
Trigger(s):	Asset Condition, Operating Requirements		
Outcomes:	Operational Effectiveness		

Objective:

Enable regular upkeep of HOSSM's General Plant assets including IT software and hardware, vehicle fleet, office furniture, and other similar items through periodic replacement as assets reach the end of their respective lifecycles.

Need:

To facilitate safe and efficient conduct of its ongoing business activities HOSSM needs to maintain its IT, facilities and fleet assets in an appropriate state of repair. Given the relatively short useful lives for many of the assets in this category, ongoing replacement, guided by processes described in Section 3.1.3.3 of this Plan will continue as required.

Alternatives:

Alternative #1: "Do Nothing"

This alternative is not recommended, as it does not address the issue of HOSSM's general plant assets reaching the end of useful life condition and requiring replacement to enable HOSSM staff to complete their work responsibilities in a safe environment.

Alternative #2: Undertake Regular Replacements

This is the recommended alternative for the program as it addresses the needs and is consistent with HOSSM's and Hydro One's asset management policies for the General Plant category.

Investment Description:

This small investment category will be assessed on an ongoing basis by HOSSM personnel to determine the most pressing needs on the basis of prioritization across IT, Fleet and other small asset classes like office furniture. As the integration with Hydro One continues, HOSSM expects to manage the costs of this program by leveraging any applicable synergies that may be available through resources accessible to the lager utility.

Project Costs:

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital Expenditures ($M)	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$1.1

**numbers may not add up due to rounding*

Investment Results and RRF Outcomes:

Operational Effectiveness	• Promotes ongoing safe and reliable operation of HOSSM Fleet, IT and Facilities.

ieso
Connecting Today.
Powering Tomorrow.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

May 28, 2018

via email

Mr. Kevin Lewis
General Manager
Hydro One Sault Ste. Marie LP
2 Sackville Road, Suite B,
Sault Ste. Marie ON P6B 6J6

Dear Mr. Lewis:

Re: Independent Electricity System Operator
Regional Planning Progress Update - East Lake Superior Region

The Independent Electricity System Operator ("IESO") is writing to provide an update on regional planning activities for the East Lake Superior Region.

In the first cycle of regional planning, a Needs Assessment for the region was completed in 2014 and concluded that no further regional coordinated planning was required. As such, neither a Scoping Assessment nor Integrated Regional Resource Plan was required in the first cycle.

The second cycle of regional planning for the East Lake Superior Region is not scheduled to begin until 2019.

The IESO trusts this information provides the information being sought on the current status of regional planning in the East Lake Superior Region. However, should you have any questions, please do not hesitate to contact me.

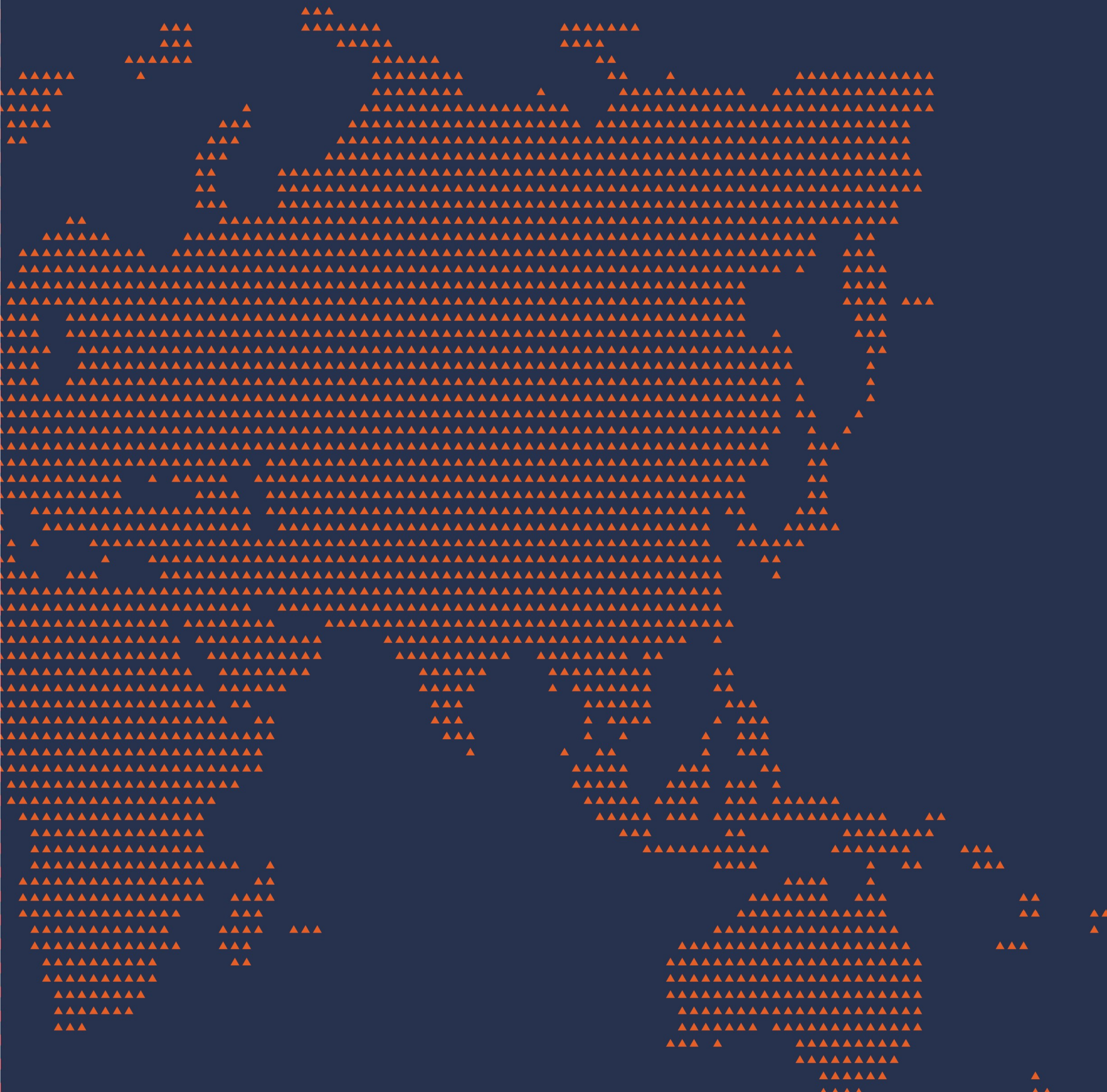
Yours truly,

Tam Wagner
Senior Manager, Regulatory Affairs

cc: Bob Chow, Director, Transmission Planning, IESO
Ahmed Maria, Director, Transmission Planning, IESO
Ajay Garg, Manager, Regional Planning & Major Projects Coordination, Hydro One

METSCO

MAKING IT POSSIBLE



Asset Condition Assessment for the Hydro One Sault Ste. Marie Transmission System

Report & Conclusions

Prepared For:

Hydro One Sault Ste. Marie Inc.

Hydro One Networks Inc.

Prepared By:

METSCO Energy Solutions
2550 Matheson Blvd East
Mississauga, ON, L4W 4Z1

Disclaimer

This 2018 report has been prepared by METSCO Energy Solutions Inc. (“METSCO”) for Hydro One Sault Ste. Marie LP. (“HOSSM) and Hydro One Networks Inc. (“Hydro One”). Neither Hydro One nor, HOSSM, nor METSCO, nor any other person acting on their behalf makes any warranty, expressed or implied, or assumes any legal responsibility for the accuracy of any information or for the completeness or usefulness of any process disclosed or results presented, or accepts liability for the use, or damages resulting from the use, thereof. Any reference in this report to any specific process or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by HOSSM, Hydro One or METSCO.

Asset Condition Assessment of Hydro One Sault Ste. Marie Transmission System

Final Draft Report

METSCO Report # 18-136

July 6, 2018

Experts:

Robert Otal, B.Eng., P.Eng.
Director, Asset Management & Analytics

G. S.

Gokhan Saltan, B. Eng., P. Eng.
Senior Associate, Transmission Planning

Dmitry Balashov, MPA, MBA
Director, Utility Strategy and Economic Regulation

Expert Support:

Aseel Alfalahi, B.Eng.
Associate, Asset Management Analytics

James Warburton, B.Sc., B.Eng. (in progress)
Student Intern Associate, Asset Management Analytics

Gamaliel Obinyan, B.Eng. (in progress)
Student Intern Associate, Asset Management Analytics

Approved By:

Thor Hjartarson, M. Sc., P. Eng.
Chief Executive Officer

Version History

Version	Date	Description
Version 1	June 10, 2018	Pre-Final Draft Report
Version 1.1	July 6 2018	Final report

Table of Contents

Table of Figures

1. About this Report

Hydro One Sault Ste. Marie LP ("HOSSM") and Hydro One Networks Inc ("Hydro One") engaged METSCO Energy Solutions to prepare a comprehensive Asset Condition Assessment ("ACA") study for the assets comprising HOSSM's transmission system. The ACA is required as one of the key inputs for preparation of HOSSM's first multi-year Transmission System Plan, prepared in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

HOSSM is a regulated electricity transmitter in Ontario, operating the assets formerly owned by Great Lakes power Transmission LP. ("GLPT") following their 2016 acquisition by Hydro One Inc. HOSSM assets and operations supporting them are currently being integrated into the operations of Hydro One Inc.'s main transmission subsidiary – Hydro One Transmission Networks Inc. METSCO understands that its report represents the first instance where HOSSM's assets have undergone quantitative multi-factor condition-based analysis across all key classes. While we are aware that our methodology to asset Health Index calculation differs in certain respects to that used by Hydro One (the acquiring utility), METSCO has been encouraged to employ our own approach – to provide an external perspective on the state of HOSSM's plant at this juncture of its incorporation into Hydro One. We do, however expect that in the future HOSSM's assets will undergo condition assessments using approaches employed by Hydro One.

In preparation of this report, METSCO relied on the following data sources:

- Asset inspection and testing data collected by HOSSM employees and external contractors;
- Trouble reports for certain types of equipment completed by HOSSM employees;
- METSCO's own site inspections completed over a total of five days of site visits;
- Telephone and in-person Interviews with HOSSM and Hydro One asset management staff;
- Past reports pertaining specific to assets or undertakings prepared by other consultancies.

Overall, HOSSM collects a substantial amount of information regarding the state of its assets, which enabled METSCO to prepare multi-factor Health Indices for nearly all of the asset classes that we examined in the scope of this project, which included all major station and line equipment operated by the utility. In the concluding section of this report, METSCO makes a number of recommendations aimed at enhancing the scope and quality of data collection efforts, which Hydro One and HOSSM may wish to consider in the course of ongoing integration work.

2. Executive Summary

2.1. Context of the Study

Hydro One Sault Ste. Marie LP ("HOSSM") is an electricity transmitter operating a system made up of approximately 560 km of lines and 15 stations located in Northern Ontario, along the eastern shore of Lake Superior, between Sault Ste. Marie and Wawa ON. HOSSM is a subsidiary of Hydro One Inc. ("HOI"), which acquired the company from Brookfield Asset Management in 2016. HOSSM's assets are in the process of being incorporated into the operations of HOI's other transmission subsidiary – Hydro One Transmission Networks Inc. ("Hydro One"). HOSSM and Hydro One engaged METSCO to complete a comprehensive Asset Condition Assessment (ACA) for HOSSM's system.

2.2. Scope of the Study

METSCO's work included collection, digitization, analysis and verification of HOSSM's asset records, along with its own site inspection data. In total METSCO assessed and developed health indices for 15 classes of HOSSM's assets, including:

Transmission Line Equipment:

- Line Conductor;
- Wood Line Support Structures;
- Composite Line Support Structures;
- Steel (Lattice and Pole) Line Support Structures;

Transmission Station Equipment:

- Power Transformers;
- Oil Circuit Breakers;
- SF6 Circuit Breakers;
- Vacuum Circuit Breakers;
- Switches;
- Circuit Switchers;
- Shunt Capacitors;
- Shunt Reactors;
- Protection Relays;
- Instrument Transformers;
- Station Batteries.

The majority of data components of Health Indices for each of the above-noted asset classes came from asset records maintained by HOSSM as a part of its regular asset management function and collected in compliance with the Transmission System Code requirements. In certain cases, however, METSCO also relied on information from external reports prepared by other consultants engaged by HOSSM or its predecessor to provide expert advice on a particular project or asset class.

2.3. Methodology and Findings

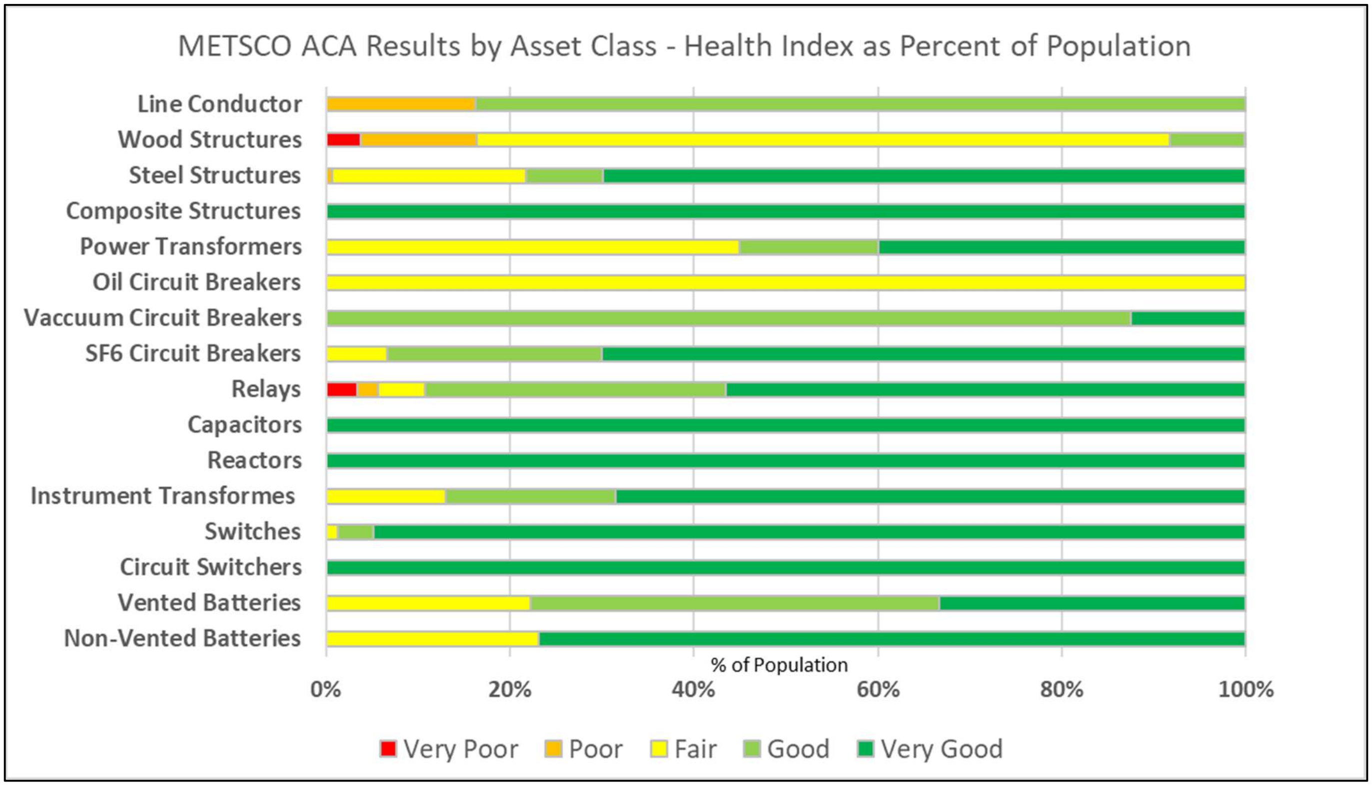
For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from – Very Good to Very Poor. The numerical Health Index (HI) corresponding to each condition category serves as an indicator of an asset's remaining life given as a percentage. Figure 2.1 presents the HI ranges corresponding to each condition scores, along with their corresponding implications as to the follow-up actions on the part of the asset manager.

Figure 2.1: Health Index and Asset Condition-Based Framework

Health Index Score (%)	Condition	Description	Implications
85-100	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
70-85	Good	Significant Deterioration of some components	Normal Maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on unit's criticality
30-50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate, considering risk and consequences of failure
0-30	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated Health Indices for every asset class in the scope of its assessment. The Health Index for each asset class is made up of available and relevant "condition parameters" – individual characteristics of the state of an asset's components – each with its own sub-scale of assessment, and a weighting contribution that represents the percentage in the overall HI made up by the particular parameter. METSCO's findings for each asset class developed on the basis of this methodology and described in more detail in Section 4 of this report, are provided in Figure 2.2 below.

Figure 2.2: Asset Condition Assessment Results by Asset Class



As the figure above indicates, the majority of assets installed on HOSSM's transmission system are in a Fair condition or better, with only four asset classes containing units found to be in a Poor or Very Poor condition. While it points to a relatively healthy asset base and provides a reasonable overview of the state of the system, this lens of analysis does not factor in several practical considerations of managing assets – such as replacement costs of units across different asset classes, or the relative sizes of asset populations. Both of these factors offer additional insights as to the practical implications of ACA results, as they provide an indication of the level of enhanced maintenance and testing or replacement/refurbishment work that HOSSM may wish to undertake on the basis of the results of this ACA.

Factoring in the above-noted considerations on the basis of an average replacement cost for a typical unit within each asset class, and the relative sizes of asset class populations, it is possible to derive average dollar-weighted Health Indices for the entire asset base or its sub-components. METSCO performed such a calculation for the HOSSM assets as a whole, as well as its two main sub-components – namely the Lines and Stations assets. Figure 2.3 provides the results of this assessment, which adds a dimension of economics to the calculation of asset condition across asset classes. METSCO calculated the average grade for a specific sub-system by taking the product of the total estimated replacement cost[1] of an asset class and the average Health Index within that class, and then comparing across the entire group of asset classes within the sub-system.

Figure 2.3: Average Dollar-Weighted System Health Index

System / Subsystem	Average Grade	Condition
Lines	63%	Fair
Stations	82%	Good
Overall System	72%	Good

As Figure 2.3 indicates, the Line portion of the HOSSM system is in a Fair condition (63% Health Index) on the basis of average dollar-weighted HI analysis – largely reflecting the condition and replacement costs of the Wood Support structures, which make up 86% of all structures. The station assets are in a better condition, with the average dollar-weighted Health Index grade of 82%. Combining the scores for the two subsystems yields the Overall HOSSM System Health Index of 72%, which corresponds to a Good condition rating, approaching the Fair condition territory.

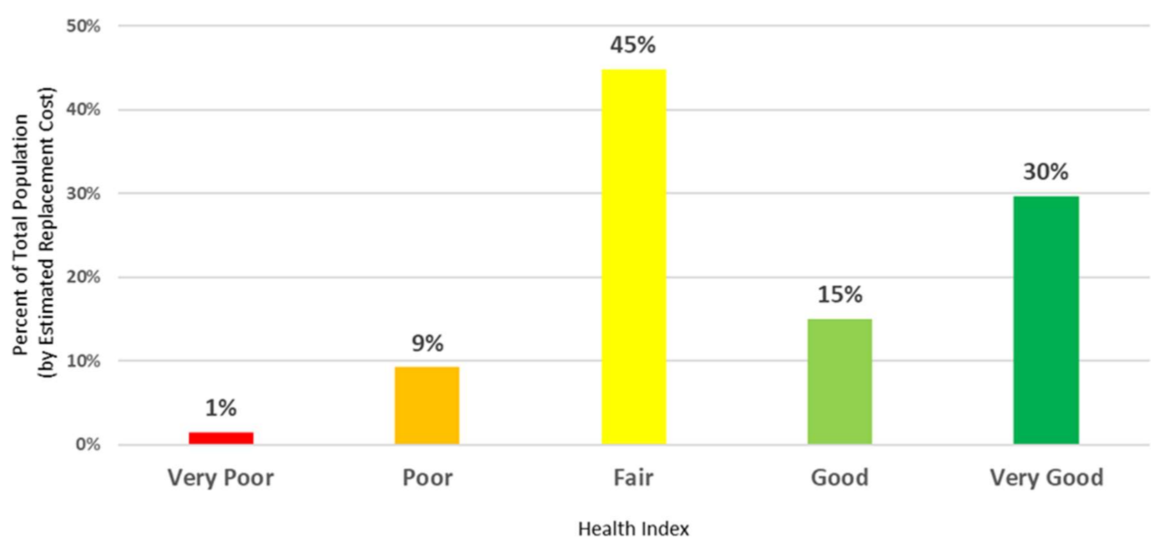
Using the dollar-weighted average system condition data across all asset classes analyzed, METSCO was also able to calculate the distribution of all of HOSSM's assets within the scope of this study across the five condition categories, as captured in Figure 2-3 above. METSCO believes that this manner of presenting the ACA findings should assist HOSSM in strategic planning exercises over the longer term, as it represents a proxy for the magnitude of financial implications associated with its asset base that need to be addressed through asset intervention planning in the coming years and decades.

The distribution presented in Figure 2.4 on the following page suggests that HOSSM has been a prudent asset manager over the years, with only 10% of its plant found to be in the Very Poor and Poor condition (which corresponds largely to the population of

[1] For the purposes of this analysis, METSCO used publicly available equipment/materials costs only, not factoring in capitalized labour costs that typically make up over 50% of the total capital cost.

deteriorated wood structures). Moreover, given that nearly half of its system by estimated replacement value is currently in the Fair condition, implies that the utility should continue its ongoing asset replacement programs to manage the backlog. As HOSSM proceeds along the path of integrating its asset management function with that of Hydro One, adopting the larger utility's risk-based planning and management processes, METSCO expects HOSSM to be in an increasingly good position to manage this upcoming bow wave of deteriorating assets through evidence-based pacing and prioritization decisions.

Figure 2.4: System Average Asset Condition Distribution



As a final dimension of our analysis, METSCO also examined asset condition on the basis of criticality of equipment by its electrical location to the overall reliability and operability of the HOSSM system as a whole. The purpose of this "segmentation" of asset condition analysis is to help the utility prioritize potential intervention decisions on the basis of importance of a particular asset to the system's continued functionality under normal operating conditions.

To provide this layer of assessment, METSCO divided HOSSM's line and station infrastructure into three "Levels." Level One represents the backbone lines and stations that support bulk power flows into and out of the HOSSM service territory, and across the three core areas of the HOSSM network anchored by the MacKay, Third Line, and Anjigami Transmission Stations (TS) respectively. Level Two lines and stations are those that support and interconnect multiple elements within each of the three sub-areas of the HOSSM system.

Finally, Level Three stations are the radial ends of the system that supply load to or collect generation from individual HOSSM customers. While an equipment-related outage at one of the Level Three facilities would be the least consequential for the operations of the system as a whole, it would be most impactful to specific customers, particularly since there are no limited means of establishing alternative paths to service these customers while the failed equipment on the normal supply path undergoes repairs or replacement. Accordingly, the significance of Level Three assets vis-à-vis the rest of the system depends largely on the perspective of the analysis. In any case, given the customer-centric nature of the Ontario Energy Board's (OEB) Renewed Regulatory Framework (RRF) that currently governs the operations of Ontario's regulated transmitters, facilities that ensure service continuity for specific customers warrant being placed into a separate category to help the utility plan the scope and sequencing of future intervention activities across the system.

Based on this categorization into three levels of significance to continued system operations, the results of METSCO's ACA are captured in the Figure 2.5 for HOSSM's station infrastructure. We note that the scores shown are averages of all assets of a given type at each location.

Figure 2.5: Average Asset Class Health Index for Station Assets by System Criticality

Station	Power Transformers	Circuit Breakers	Instrument Transformers	Batteries	Switches	Relays	Circuit Switchers	Capacitor Banks	Reactors	Station Average
Level 1 Stations										
Third Line	71%	96%	100%	72%	92%	89%	-	94%	100%	89%
Mackay	93%	93%	99%	75%	95%	84%	-	-	94%	90%
Anjigami	85%	-	-	-	99%	97%	-	-	-	93%
Level 2 Stations										
Clergue	58%	55%	60%	88%	96%	74%	-	-	-	72%
Gartshore	-	85%	-	75%	75%	85%	-	-	-	80%
Steelton	-	76%	-	75%	98%	82%	-	-	-	83%
Watson	85%	74%	88%	76%	99%	69%	-	-	-	82%
Magpie	-	-	-	100%	97%	87%	-	-	-	95%
Level 3 Stations										
Echo River	56%	62%	75%	100%	-	86%	100%	-	-	80%
Hollingsworth	85%	74%	83%	100%	93%	87%	-	-	-	87%
Northern Ave	73%	86%	85%	50%	99%	74%	-	-	-	78%
Batchawana	69%	-	-	-	-	-	93%	-	-	81%
Goulais	64%	-	-	-	-	-	95%	-	-	80%
Highway 101	-	-	-	88%	-	100%	-	-	-	94%
Andrews	91%	-	-	100%	-	85%	-	-	-	92%

As the above figure[2] indicates, the vast majority of HOSSM's Level One station assets are in a Very Good condition, with a notable exception of the Third Line TS, where one of the power transformers is in a Fair condition and warrants follow-up in the near term. HOSSM's Level Two assets are on average in a Good or Very Good condition, aside

[2] A dash in a given cell indicates that a particular asset class is not present at a given station.

from the Clergue TS, whose larger station assets like power transformers and circuit breakers show a considerable amount of deterioration, warranting a closer follow-up.

The average condition of HOSSM assets, and particularly the power transformer and circuit breaker fleet) is the most deteriorated at HOSSM's Level Three stations that serve to interconnect specific load and generation customers. While these assets carry the least significance for the overall functionality of the utility's power system, they are critical from the perspective of providing reliable service to HOSSM's customers, which include two Local Distribution Companies (LDCs), multiple generators and a large industrial manufacturing facility.

Figure 2.6 provides a criticality-based segmentation of METSCO's findings for HOSSM's line assets, which are also subdivided into three Levels according to their criticality.

Figure 2.6: Average Asset Class Health Index for Line Assets by System Criticality

Circuit	Average Structure HI	Average Conductor HI*
Level 1 Lines		
P21G	81%	Good
P22G	50%	
K24G	50%	
W23K	50%	
No 3 Sault	55%	Poor

Circuit	Average Structure HI	Average Conductor HI*
Level 2 Lines		
No 1 Garthshore	45%	Good
No 2 Garthshore	68%	
No 1 Algoma	82%	
No 2 Algoma	76%	
No 3 Algoma	80%	
No 1 High Falls	50%	
No 2 High Falls	55%	
No 1 Clergue	99%	
No 2 Clergue	100%	
Magpie	56%	

Circuit	Average Structure HI	Average Conductor HI*
Level 3 Lines		
Andrews	57%	Good
Hogg	78%	
No 3 Garthshore	78%	
No 1 MacKay	44%	
No 2 MacKay	41%	
Northern Avenue	78%	
Steephill	61%	
Harris	63%	
Mission Falls	65%	
Hollingsworth	100%	
Leigh's Bay	88%	
Limer	49%	
Anjigami	45%	

Since HOSSM's assets and operations are in the process of being integrated into the operations of Hydro One Networks, METSCO expects that HOSSM's practices related to inspection and testing of equipment will be aligned with the acquiring utility's approaches over the coming years. Considering that this development will likely bring about a number of changes to HOSSM's current practices (an observation that we make on the basis of our knowledge of Hydro One's processes from previous engagements), METSCO does not provide an extensive list of recommendations for incremental enhancements at this time. However, we do see it as important for HOSSM to transition to electronic collection, and centralized storage of all of its asset data to streamline future condition assessment efforts.

3. Introduction

3.1. Overview of the Study

Hydro One Sault Ste. Marie LP (HOSSM) is a licensed electricity transmitter whose system is located along the eastern shore of the Lake Superior, approximately between the municipalities of Sault Ste. Marie and Wawa in Northern Ontario. HOSSM is the second largest regulated transmitter in Ontario by system length and the amount of revenue requirement (annual regulated revenues approved for the financing of its operations for recovery from ratepayers). Following a 2016 acquisition by Hydro One Inc ("HOI"), HOSSM is now in the process of being integrated with Hydro One Networks ("Hydro One") – HOI's main transmission subsidiary and the owner and operator of the predominant portion of Ontario's transmission system.

HOSSM and Hydro One engaged METSCO to complete an Asset Condition Assessment of HOSSM's assets ahead of preparation of the utility's first comprehensive multi-year Transmission System Plan ("TSP") to be submitted to the OEB as a part of a regulatory proceeding. METSCO understands that this is the first comprehensive Asset Condition Assessment ("ACA") developed for HOSSM or its predecessor, aside from several previous single-issue studies addressing condition or functionality of equipment within a specific asset class, or the scope of a specific project contemplated in the past. Notwithstanding the ongoing integration of HOSSM into the Hydro One operations, and the eventual adoption of Hydro One's ACA methodologies for the purpose of ongoing management of HOSSM assets, HOSSM and Hydro One asked METSCO to rely on its own methodology in preparation of this TSP, in order to lend an external perspective on the state of HOSSM's assets, to assist both parties in the course of ongoing integration work.

3.2. METSCO's ACA Methodology

3.2.1. Health Indices and their Implications

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from "Very Good" to "Very Poor." To assign each asset into one of the categories, METSCO constructs numerical Health Indices for each asset class that capture information on individual degradation factors contributing to that asset's declining condition over time. Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along pre-defined scales. The final Health Index – expressed as a value between 0% and 100% is a weighted sum of scores of individual degradation factors, with each of the five condition categories ("Very Good," "Good," "Fair," "Poor," "Very Poor") corresponding to a numerical band that are roughly equivalent to the percentage of remaining useful life for the given asset. For example, the condition score of Very Good indicates assets with Health Indices between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated Health Indices between 0% and 30%.

To put the calculation of Health Indices into the context of available data, METSCO supplemented its Health Index findings with the calculation of a Data Availability Index (DAI), which indicates the percentage of total asset population for which the condition information is available. DAI calculations use the same weighted sum product methodology as the Health Indices for which they are calculated. See section 5 of this report for more information on METSCO's methodologies for calculating Health Indices and Data Availability Indices.

3.2.2. Data Sources

To assess the condition of HOSSM's transmission system assets, METSCO used a variety of data sources available to HOSSM that consistently track information on the state of repair, functionality or degradation of a particular type of assets, along with their nameplate demographics, operating history, and other statistics. Most of this data came from primary sources such as equipment inspection forms completed by HOSSM staff or contractors, results of specific technical tests such as Dissolved Gas Analysis (DGA) of transformer oil, or corporate asset registries containing information on asset vintage, model and year of commissioning.

In instances where information available from primary sources was insufficient to construct multi-factor Health Indices, METSCO relied on available secondary sources, such as assessments prepared by other external consultants that opined on, or empirically tested certain assets to determine their condition or continued usability. This report clearly denotes all instances where the findings of other external parties form the part of METSCO's Health Index calculations.

3.2.3. METSCO's Engagement in the Project

METSCO's work in completing this study can be separated into five phases described below:

Initial Information Gathering – including initial interviews with HOSSM staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources, and confirm the key assumptions regarding these factors with HOSSM and HONI experts through a series of interviews.

Database Construction – activities to construct a single database of condition-related information for each material HOSSM asset class, including digitization of HOSSM's paper-based asset inspection records, analysis and consolidation of electronic databases containing results of technical tests performed by HOSSM contractors, and verification of the entire database against the available asset ledgers. In certain cases, this step also included collection of condition data to fill certain identified gaps in the analysis of existing information.

Data Integrity Verification – site inspections and interviews with HONI experts to compare the scales used by HOSSM staff in performing visual inspections against METSCO's interpretation of what features would define a unit in a particular condition assigned through visual inspection. In the course of its interviews with HOSSM staff, METSCO also sought to explore whether and to what extent the utility's staff has historically experienced any consistent issues with certain asset types, models or vintages, which may not be adequately captured in inspection forms.

HI and DAI Calculation and Calibration – upon confirming the integrity of its condition dataset along with accuracy of assumptions made in its preparation, METSCO calculated the Health Indices for all asset classes. As we reviewed the initial results of our calculations, we compared them to the to our notes taken during site visits and interviews, making adjustments to the weightings of certain criteria where numerical results did not align with the issues we saw on the ground, where the asset types in question did not correspond to the default weightings assigned by the model (e.g. indoor vs. outdoor breakers) or where the lack of information of certain type may have overstated the significance of available data points. This calibration is a normal part of every Health Index calculation that METSCO performs for its clients.

Results Segmentation – the final phase of our engagement involved analyzing the results of our assessment in several different formats. These include the typical default ACA presentation format that showcases the distribution of Health Indices between Very Good, Good, Fair, Poor, and Very Poor across each asset class based on the percentage of assets in every condition across the population. Beyond this "default" presentation method, however, METSCO evaluated two other modes of ACA results segmentation – including a dollar-weighted average system condition score, where the Lines and Stations subcategories and the system as a whole are assigned condition scores, including the distribution of all system assets across the five condition categories based on the estimated replacement values of all assets. Finally, METSCO evaluated and presented its results on a high-level criticality continuum, corresponding to the role a given circuit or station plays in maintaining the overall reliability of the system as whole.

See Section 5 for information on METSCO's findings along with the methodologies underlying them.

3.3. ACA Results and Implications

On average, HOSSM's system is in a Good condition across all major lines and stations assets comprising its system. While certain asset classes exhibit a greater degradation or presence of obsolescent units than others, HOSSM and its predecessor GLPT appear to have managed their system responsibly, making prudent intervention decisions. We note, however, that in a number of instances our findings may overstate the condition of asset classes due to the lack of sufficient data across certain parameters. For instance, while the numerical Health Indices calculated on the basis of available data indicate that virtually the entire population of Switches is in a Very Good condition, this finding is contrary to our experience of conducting and evaluating ACAs for transmission and distribution utilities across North America, which suggests that all assets exhibit increasing signs of deterioration over time, and assets from one class in a given location (e.g. station) should generally experience similar degradation trajectories.

Section 4 of this document provides a technical overview of HOSSM's system, METSCO's observations from site visits and data consolidation activities.

Section 5 provides a description of METSCO's HI and DAI calculation methodologies.

Section 6 contains our specific findings for each asset class.

Section 7 provides our overall findings, along with other concluding remarks to inform Hydro One and HOSSM's further integration activities.

4. Key Information on HOSSM System

4.1. Technical Background on HOSSM's Transmission System

HOSSM's transmission system consists of 560 circuit kilometers of transmission lines in Northern Ontario operating predominantly at 230, 115 and 44 kilovolts (kV) and 15 transmission stations (TS) spanning an area of approximately 12,000 square kilometers. Figure 4.1 provides a map of the HOSSM system and its key components.

Figure 4.1: HOSSM Transmission System Map

Formerly a part of a vertically integrated utility (Great Lakes Power) that included generation, transmission and distribution facilities, HOSSM's transmission system supplies power to two distribution utilities (Algoma Power Inc. and PUC Distribution Inc.) connected at a total of four locations, and four industrial customers connected at transmission voltages. In addition to serving load customers, HOSSM connects a total of 894 megawatts (MW) of transmission connected and distribution-embedded generation, which predominantly consists of hydroelectric and wind power resources. The utility is interconnected with Hydro One's transmission system via Hydro One's Wawa and Mississagi TS.

From the standpoint of customer demand, HOSSM's transmission system is winter-peaking, with a peak load of approximately 350 MW in the winter season, and 300 MW during the summer months. The utility's system is subdivided into three operating areas, corresponding to the largest population centers going north-south through the system territory. Figure 4.2 provides system statistics for each area, namely the Wawa, Montreal River and Sault Ste. Marie Areas.

Figure 4.2: HOSSM Geographical Subsystem Statistics

Subsystem	230 kV cct km	115 kV cct km	44 kV cct km	Transmission Stations	Industrial Customers	LDC Connections	Generators
Wawa Area	74	74	11	5	2	1	7
Montreal River Area	-	37	-	3	-	1	5
Sault Ste. Marie Area	245	121	-	7	2	2	4
Total	**319**	**232**	**11**	**15**	**4**	**4**	**16**

4.1.1. Equipment Configuration and Criticality

In the process of our initial review of HOSSM's system and individual assets, METSCO identified a number of considerations that warrant emphasis ahead of assessing the overall asset condition. While HOSSM refers to all of its 15 stations as "Transmission Stations" the stations vary significantly by the type of equipment they contain and the role that they play on the system. For example, four of the stations, (Garthshore, Steelton, Magpie and Highway 101 TS) are not equipped with power transformers, as they collect generation, or feed customers directly at transmission voltages.[3] Stations that are equipped with transformers vary significantly in their configuration and level of available redundancies. For instance, five of the 11 stations that are equipped with transformers, have only one power transformer unit in service.[4] The direct implication of such a service configuration is that an extended transformer outage compromises the station's ability to provide service for an extended period of time while an outage is rectified. While customers connected to some of the stations can be served through an alternative path, this is not the case for all stations and customers that these assets connect.

The existence of customers served by single contingency radial assets is certainly not unique to the HOSSM system. However, when assessing condition of assets that represent the only means of supplying a customer, utilities may be justified to commence planning for, or execution of asset intervention work earlier in that asset's lifecycle than they typically would for an asset backed up by a redundant path, other considerations being equal. For instance, while a transformer found to be in a Fair condition may not require near-term follow-up at a station where other assets are capable of safely supporting its load, the same transformer deployed at station with no equipment redundancies represent a higher *risk* to the customers it supplies and by extension, the utility mandated to provide reliable supply to its customers. While the *probability* of failure for that transformer in Fair condition is the same in both scenarios, the *impact* of its failure is far more significant in a single-contingency scenario, as it would lead to a prolonged outage until the failed unit is either repaired or replaced.

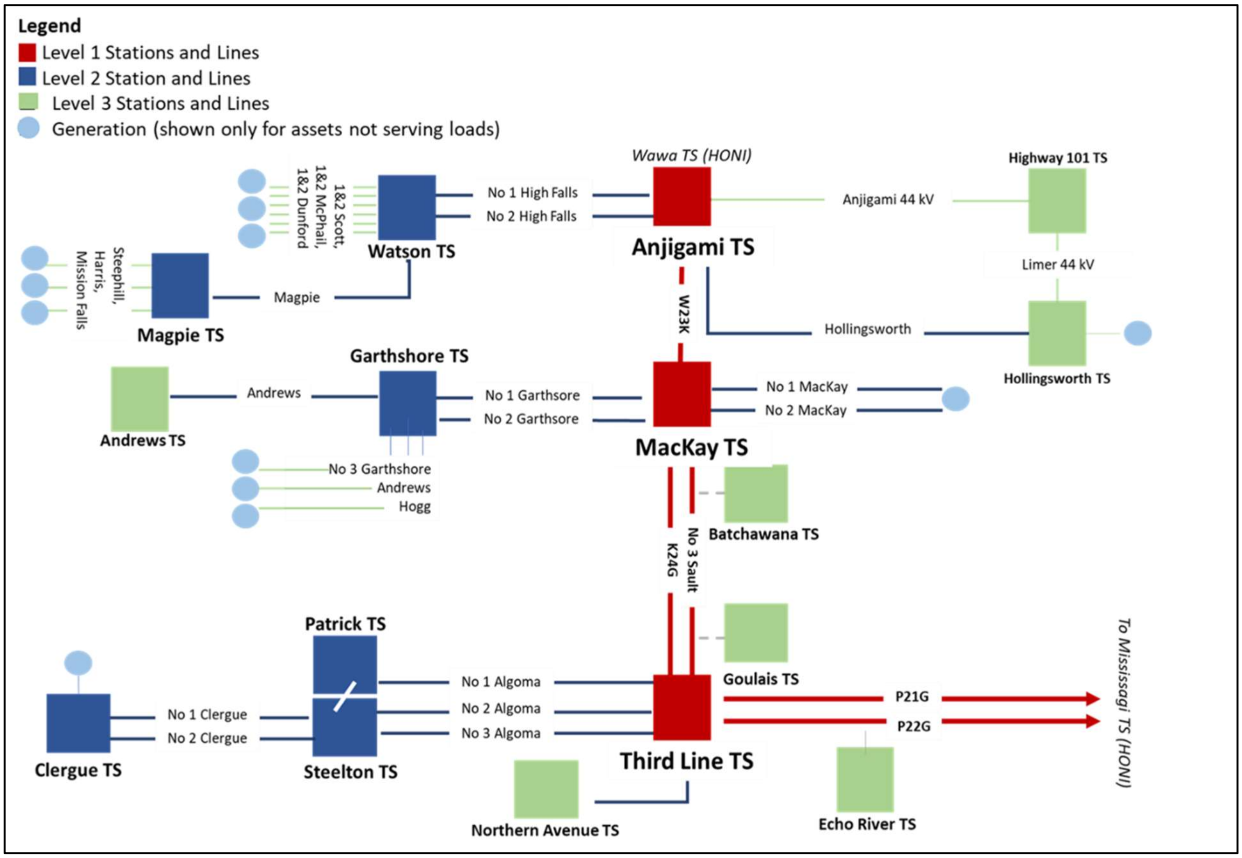
[3] We understand from HOSSM that for regulatory purposes, its 44 kV circuits and Highway 101 TS that operates at this voltage (technically considered distribution in Ontario) are deemed to perform a transmission function.

[4] Batchawana and Goulas TS have a total of three spare transformer units between them, however, they are not connected to the system. We understand that these represent units that have been previously removed from other locations as they were approaching the ends of their operating lives and kept on hand in case of contingencies.

The previous paragraph represents an example of employing the findings of an Asset Condition Assessments in a manner that accounts for the risks underlying the operation of specific assets based on their condition, location, past performance history, the number and profile of customers they serve, and many other potential variables. METSCO is a proponent of a risk-based approach to system planning, where a utility's asset intervention plans seek to minimize the aggregate risk to continued system operation. Failure risks are calculated on the basis of multiple inputs in addition to asset condition, including historical Failure Curves (statistically derived functions that showcase an asset's probability of failure at a given age) Customer Interruption Costs (estimates of customer willingness to pay to avoid an outage) and others.

METSCO understands that HOSSM plans to use the results of this ACA in developing a multi-year Transmission System Plan using a risk-based planning framework in place at Hydro One. While asset risk assessment is not in the scope of this ACA engagement, METSCO believes that presenting the results of this study in a manner consistent with risk-based planning will be of assistance to HOSSM. To accomplish this, METSCO categorized all of HOSSM's stations and lines into three groups (Levels 1, 2 and 3) corresponding to our assessment of each asset's criticality to continued operation of HOSSM's system as a whole, and reliable service to its individual customers. Figure 4.3, located on the following page contains a graphic representation of our simple criticality assessment framework. Importantly, the criticality scale that the figure depicts can be viewed bidirectionally: while individual Level 1 assets are the most critical from the perspective of ensuring reliable operation of the entire system, they are less critical from the perspective of individual customers connected via radial (Level 3) assets, failure of which would compromise their service even if the rest of the system was operating as intended.

Figure 4.3: HOSSM Asset Criticality Assessment by Impact on Overall System Reliability



Level 1 stations and lines depicted in red and located in the center of the figure represent the “bulk” system assets that ensure reliable flows of power throughout the HOSSM system and through to Hydro One’s Wawa and Mississagi Transmission stations where the HOSSM system terminates. The three stations in this category correspond to the three subsystems discussed above, which support the power flows across the rest of the system, and in the case of Third Line TS, support the largest amount of load served by the utility.

Level 2 stations and lines, depicted in blue, represent the second tier of assets from the perspective of system criticality. Most of these stations and lines interconnect downstream support multiple generation and/or load connections located downstream.

Finally, the **Level 3** stations and lines depicted in light green and located towards the edges of the figure, represent terminal stations supporting customer loads connected at distribution voltages, or individual generating stations.

As noted earlier, while Level 3 assets may be seen as least critical from the standpoint of maintaining the system's overall reliability and operability, their continued operation is critical for the provision of service to generators and loads connected to them. In developing system plans utilities must balance the considerations of maintaining the overall system reliability and providing reliable service to end-use customers. We will return to this conceptual asset criticality framework in Section 5, where we will examine the results of our asset condition assessment from several perspectives, including criticality to continued system operation.

4.1.2. Equipment Types, Vintages and Legacy Issues

Like most parts of Ontario's transmission grid, HOSSM's transmission system developed in stages over time, in response to particular drivers related to development of hydroelectric generation sources in the area, establishment of large industrial operations or residential growth. As a result, the system features a number of different types and vintages of equipment within the same asset class, further impacted by asset renewal activities that occurred over time.

Among the assets characterized by significant variety of designs and vintages are circuit breakers, where the assets include the SF6, Vacuum, and Minimum Oil technologies, with the latest type being widely considered to be obsolete on the basis of METSCO's experience. Similarly, the population of Protection Relays deployed by HOSSM still includes a number of electromechanical relays that have been largely phased out across the sector, along with a number of more contemporary technologies, including the latest digital relays installed in the last five years.

The utility's circuits are currently served by nine different types of conductors, which may be considered excessive for a utility of its size. Finally, the circuits are supported by a mix of wooden (86%), composite fiberglass (9%), steel pole (4%) and steel lattice (1%) support structures. HOSSM's deployment of composite structures reportedly represents a strategic decision taken in mid-2000's to replace all deteriorated wooden structures with composite structures going forward, in light of significant damage that the wooden structures sustain from the woodpeckers, insects and other environmental factors, causing their degradation far earlier than a typical 40-50-year lifespan commonly assumed for these assets.

Among the notable legacy issues are also a number of safety clearance violations due to incremental modifications of station configuration, coupled with the evolution of industry safety standards. In a number of locations, such as Goulais and Batchawana TS, these issues cannot be addressed within the footprint of the existing stations due to spatial restrictions dictated by the surrounding terrain. In other cases, safety clearance issues are seasonal in their nature, such as when significant accumulation of snow violates the ground clearance height for the lines exiting the station grounds. Setback violations also reportedly exist on some of the line circuits.

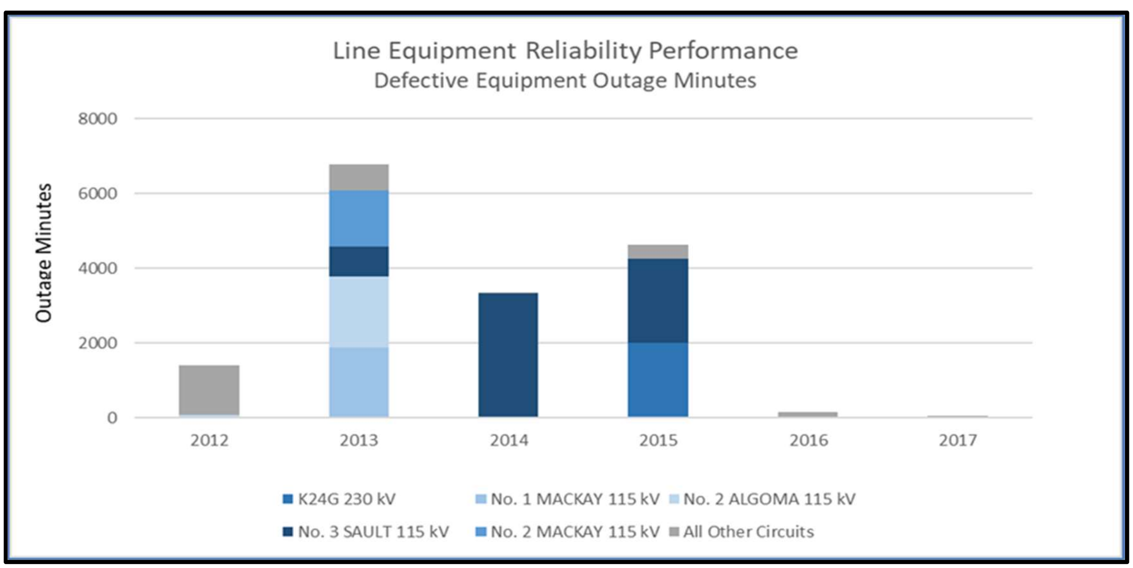
4.1.3. Equipment Reliability Performance

In the course of our initial examination of HOSSM's system data, we completed a cursory review of HOSSM's outage statistics for the 2012-2017 timeframe. Our search was focused on instances of outages attributed to malfunction of line and station equipment, to determine whether and to what extent the equipment is a significant contributor to outages that occur on the system.

Our review of station data did not reveal any notable patterns that would suggest that a particular asset class or a specific asset was responsible for a disproportionate number or an extended duration of outages. When reviewing the line outage statistics, however, METSCO noted that over the period examined, 84% of total outage duration attributed to equipment performance occurred on only five HOSSM circuits.

Of these five circuits, 39% of equipment-related outage minutes occurred on one circuit – the 115 kV No. 3 Sault circuit, which runs between MacKay and Third Line TS, feeding Batchawana and Goulais TS along the way. Returning to METSCO's asset criticality framework discussed ins Section 4.1.1., we identified the No. 3 Sault circuit as one of only five "Level 1" (or most critical) circuits on HOSSM's system, and the only 115 kV circuit to be included in this group. Moreover, unlike the remaining four circuits where the log-duration outages occurred in a single year, the No. 3 Sault circuit experienced prolonged equipment-related outages during three consecutive years (2013-2015), potentially indicating persistent issues. Figure 4.4 illustrates the historical performance of HOSSM's five worst circuits by outage duration.

Figure 4.4: Longest Equipment-Related Line Outages by Circuit



Other than the No. 3 Sault performance, we did not identify any other equipment-related reliability performance patterns that warranted further follow-up.

4.2. METSCO's Site Visits to the HOSSM Service Territory

4.2.1. Inspection Data Validation

During our engagement, METSCO staff spent a total of five days in the Sault Ste Marie area as a part of two separate engagements. The primary purpose of our visits was to validate HOSSM's data collection methodologies and calibrate the scale of its asset degradation assessment framework against our experts' understanding to ranking asset condition parameters. In the course of this work, METSCO staff conducted independent visual inspections of multiple station and line assets in the Sault area, which it subsequently confirmed with the results of HOSSM assessments. We note that these calibration exercises were limited to visual inspection parameters and did not include the review of technical testing results such as Dissolved Gas Analysis (DGA), Infrared Scanning or Doble Insulation Testing performed by HOSSM contractors.

HOSSM's current approach to visual inspections of station equipment utilizes a three-point scoring system (Good/Fair/Poor). While it is common for many Ontario utilities, the disadvantage of a three-pronged approach is that it limits the degree of granularity to which an inspection can capture the incremental degradation that takes place over years – as opposed to decades. In conducting our own inspections, METSCO used a five-point grading system (Very Good/Good/Fair/Poor/Very Poor), which represents an industry best practice for capturing incremental degradation over shorter periods of time, and as such, enables asset managers to derive more granular insights as to the relative health of utility plant. While METSCO discussed the relative benefits of the two approaches with HOSSM staff, the visual inspection results underlying our calculated Health Indices are based on HOSSM's inspection data.

Overall, HOSSM's station inspection forms capture a significant number of key visual inspection criteria, equipment gauge readings, and simple operational tests (e.g. mechanical functionality of buttons, locks etc.) to provide the asset managers with a comprehensive view of the issues that a particular piece of equipment may experience. The forms used by internal staff are consistent across the locations and include meaningful customizations to reflect specific parameters of a given asset class. However, to denote the completion of a number of tests or assessments on the forms, inspectors are merely required to check a box, indicating that a test was completed, without providing any additional information – be it in the form of relative grading or specific measurements.

Such an approach to inspection form completion may be driven by the objectives of completing inspection work as efficiently as possible. However, it significantly limits the insights that asset managers can gain when comparing inspection forms across stations or asset classes. We acknowledge that in a number of cases, we saw the evidence of saw making additional written notes next to check boxes to convey additional information. While this represents a helpful practice, the lack of standard assessment criteria underlying such observations adds a degree of subjectivity to the results recorder in this manner. We also note that a similar (checkmark-based) approach was used by some of HOSSM's contractors – in particular the Infrared Scan testing provider, where most asset tests were denoted by a simple check box, rather than a particular thermographic reading.

From the practical perspective of calculating Health Index results on the basis of forms with limited information, METSCO relied on a number of assumptions clarified with HOSSM staff. For example, in all cases where test completion was denoted by a checkmark, METSCO's default assumption was that the asset component did not exhibit any issues – leading to a grade corresponding to Good condition being assigned for the particular asset.

4.2.2. Additional Data Collection and Staff Interviews

Other than calibrating the existing scoring methodologies, we leveraged our site visits as opportunities to compile additional visual inspection data for assets where some information was missing, and/or equipment parameters where the utility does not currently collect condition information (such as the small population of Series Capacitors and Shunt Reactors). This exercise also permitted METSCO to interview HOSSM staff with direct experience of working with the assets under various loading conditions and awareness of operational issues (e.g. mechanical operation, maintenance hazards, etc.) that do not lend themselves well to being captured by condition inspections alone.

4.2.3. HOSSM's Legacy Record Keeping Practices

METSCO's initial site visit also enabled us to review the state of HOSSM's asset record keeping practices. While the utility collects a significant variety of asset-related information through staff testing and inspections, along with technical testing services provided by external contractors, the results of all assessments are kept separately, without being consolidated into a single database that would enable ongoing derivation of asset health indices or a historical trend assessment. In the cases of some testing results, such as the DGA analysis, the utility kept on hand only the summary reports of these assessments that contained limited information that would be suitable for calculation of asset Health Indices using this important diagnostic test.

The most notable issue with HOSSM's record management practices, however, is the fact that all station inspection records are completed and stored in paper-based form only, without being digitized to enable easier assessment in future planning or consolidation with other inspection or testing results. Owing to the state of HOSSM's legacy record keeping, the initial phase of METSCO's engagement on this project involved digitization of a sufficient volume of asset records and consolidation and reconciliation of all available data sources into a single database that captures condition data for all asset classes.

In certain cases, such as with wood structure assessment data, our consolidation exercise involved combining the results of two separate testing engagements performed by different contractors on different parts of the HOSSM system, while using different condition parameters and units of reference. Whereas one dataset assessed individual poles that make up multi-pole transmission support structures (such as the common H-Frame configuration), the other captured information for the combined structures only. Working with these data constraints required METSCO to employ a number of assumptions which we invariably verified with HOSSM staff. Notwithstanding these issues that accompany most asset condition assessments, we are, on balance satisfied with the amount and quality of data that we were able to obtain for calculation of asset Health Indices. Our Data Availability Indices for each asset class discussed in Section 6 corroborate this assessment.

In relaying the observations regarding the current state of HOSSM's asset record keeping, we acknowledge that the utility is presently undergoing a complex organizational transition following its acquisition by HOI. While the ongoing transition has mandated the bulk of HOSSM staff's attention to issues other than records management, METSCO understands that the scope of transition activities also includes the process for incorporation of HOSSM's asset data into Hydro One's SAP database. We expect that in the course of this work Hydro One and HOSSM will develop the methodologies for more efficient collection and consolidation of data sources.

4.2.4. Asset Classes Examined

The available maintenance and testing records enabled METSCO to calculate multi-factor Health Indices for 15 asset classes that combined the bulk of HOSSM's electrical plant. These assets include the following:

Transmission Line Equipment:

- Line Conductor;
- Wood Line Support Structures;
- Composite Line Support Structures;

- Steel (Lattice and Pole) Line Support Structures;

Transmission Station Equipment:

- Power Transformers;
- Oil Circuit Breakers;
- SF6 Circuit Breakers;
- Vacuum Circuit Breakers;
- Switches;
- Circuit Switchers;
- Shunt Capacitors;
- Shunt Reactors;
- Protection Relays;
- Instrument Transformers;
- Station Batteries.

In discussions with HOSSM, METSCO did not identify any other material asset classes with the exception of General Plant assets such as the small fleet of HOSSM vehicles, its IT software and hardware, its leased head office location, and other small fixed assets such as furniture, tools and equipment. METSCO is not an expert in conduction condition assessments for these types of assets. Based on agreement with HOSSM, they were excluded from the scope of this study.

This concludes the technical background section on the system and asset-specific characteristics that defining HOSSM's operating context. The following section of this report lays out our methodology for calculating the health indices for each asset class examined.

5. Asset Health Index Calculation Methodology

5.1. Overview of Asset Condition Assessment

Asset Condition Assessment (ACA) is the process of determining an asset Health Index, which is a quantitative expression of an asset's current condition. A brand-new asset should have a health index of 100% and an asset in very poor health should have a health index below 30%. Generating a health index provides a succinct measure of the long-term health of an asset. Figure 5.1 presents the health index ranges and the corresponding asset condition.

Figure 5.1: Health Index Ranges and Correspond Asset Condition

Health Index Score (%)	Condition	Description	Implications
85-100	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
70-85	Good	Significant Deterioration of some components	Normal Maintenance
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on unit's criticality
30-50	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate, considering risk and consequences of failure
0-30	Very Poor	Extensive serious deterioration	Asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

5.1.1. Condition Parameters:

Condition parameters of the asset are characteristic properties that are used to derive the overall health index. Condition parameters are specific to each asset class. A condition parameter can be comprised of many sub-condition parameters. For example, the “Oil Quality” condition parameter of an asset belonging to the “Station Power Transformer” class can include multiple sub-condition parameters like “Acid Number”, “IFT”, “Dielectric Strength “and “Water Content”. In the case where there are multiple sub-condition parameters contributing to a single condition parameter, the lowest sub-condition score is taken as the overall condition score for that parameter. This prevents deficiencies in an assets health from being “covered up” by averaging processes during health index calculation.

To determine the overall health index for an asset, formulations are developed based on condition parameters that can be expected to contribute to degradation and eventual failure of that particular type of asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 5.2 provides an example of a Health Index formulation table:

Figure 5.2: Health Index Formulation Components

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

The scale used to determine an asset’s score for a condition parameter is called the Condition Indicator. Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

The conversion from alphabetic ranking to numerical grade and a brief characteristic description of the grade is provided I Figure 5.3 on the following page:

Figure 5.3 Sample Letter-Numerical Conversion Chart

Letter/Number Grade	Grade Description
A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

5.1.2. Final Health Index (HI) Formulation:

The final Health index (HI), which is a function of the condition scores and weightings, is calculated on the basis of following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\%$$

Where:

- *i* - corresponds to the condition parameter/degradation parameter number within the HI formulation;
- *Numerical Grade* - represents the score as determined from the testing or field inspection procedure that is associated with condition/degradation parameter *i*,
- *Weight* - represents the relative importance of the condition/degradation parameter *i* within the health index as determined by the impact of the parameter towards the assets' overall failure
- *Total Score* - represents the highest numerical grade that can be assigned to the asset and will be used to normalize the final health index score between 0 and 100.
- *HI* - represents the produced health index result.

For condition parameters that yield especially significant evidence towards degradation of an asset, a *gating* approach is used. If the condition parameter that has been flagged as a gating parameter is below a threshold value the overall health index is reduced by one half. An example would be the "Remaining Strength" condition parameter for the Wood Pole asset class. If the remaining strength of a wood pole is less than 65%, the final health index for that asset would be divided in half. This allows for indication of severely degraded assets through condition parameters acknowledged to be critical indicators of overall asset health.

5.1.3. Health Index Results:

An asset's Health Index is given as a percentage. The Health Index is calculated only if there is sufficient condition parameter data for the asset. The subset of the total population with sufficient data is called the sample size. Health index results can be analyzed on a per-asset, per-asset-class, or per-system basis depending on the granularity required in the analysis.

5.2. Data Availability Index (DAI)

The Data Availability Index is a measure of the availability of condition parameter data for a specific asset, as they pertain to the construction of the Health Index (HI) score. The Data Availability Index is determined by comparing the sum of the weights of the condition parameters available to the total weight of the condition parameters used to construct the Health Index for an asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\%$$

Where:

- *i* - represents the condition/degradation parameter within the HI formulation,
- *Weight* - represents the relative importance of the condition/degradation parameter *i* within the health index as determined by the impact of the parameter towards the assets' overall failure
- a_i - represents the data availability coefficient, which is equal to 1 if data is available, and equal to 0 when data is unavailable.
- *DAI* - represents the data availability index result.

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. In the case where the data availability index for an asset is 0% the asset is not considered captured within the sample population.

5.2.1. Data Gaps

The Health Index formulations calculated in this study are based only on available data provided by HOSSM. In almost all circumstances additional condition parameters or tests exists that can be performed on an asset to further ascertain its state of degradation. In certain cases, condition parameters may be available for one or several assets in a class, but unavailable for others in the same class. This scenario represents a data gap, where a researcher has to decide whether the number of assets for which a particular parameter is available is sufficient to include it in the calculation of the overall Health Index. While many opinions exist as to what percentage of assets with information on particular condition parameter is sufficient to include it in the HI calculation, in most cases asset managers are best served by abandoning a condition parameter if it is available for less than 60% of the population in that asset class.

5.3. Use of Age as a Condition Parameter

There is a degree of debate within the utilities industry regarding the appropriateness of including age as a potential condition parameter for calculating asset Health Indices. At the core of the argument against the use of age in calculating asset condition is the notion that age implies a linear degradation path for an asset that does not always match the actual experience in the field.

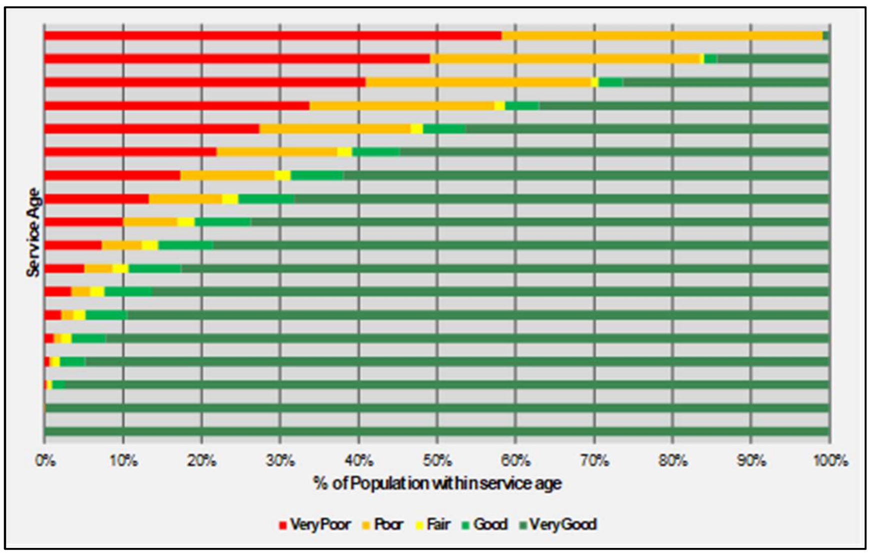
While some assets lose their structural integrity faster than would be expected with the passage of time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period of time than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, METSCO attempts to limit the instances where it relies on age as a parameter explicitly incorporated into the calculation of asset Health Indices. However, in some cases, the limited number of condition parameters available for calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing condition of complex equipment such as power transformers, which contain a number of internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

In the context of the current study, the availability of data on condition parameters varied significantly across asset classes. Where METSCO deemed the number of available condition parameters as insufficient to calculate a reliable Health Index for a particular asset class, and especially where the available information amounted to factors that do not represent the most significant degradation factors for a particular type of equipment, we included age as one of the condition parameters where nameplate data was available.

Irrespective of whether we used age data in calculating the Health Index for a particular asset class, we provide an analysis that compares calculated asset condition with the applicable service age of units comprising the asset population, using a graph depicted in the Figure 5.4 below. Contrasting the age data with the calculated condition results in this manner enables us to determine whether the expected inverse relationship between age and condition holds in the case of a given HOSSM asset class.

Figure 5.4: A Sample Asset Age vs. Condition Comparison Chart



6. Results

6.1. Health Index Results by Asset Class

6.1.1. Power Transformers

Figure 6.1: Power Transformers condition parameters scoring table

Condition	Weight	Ranking	Numerical	Max Grade
Control Box	8	A,B,C,D,E	4,3,2,1,0	32
Oil Leaks	1	A,B,C,D,E	4,3,2,1,0	4
Dissolved Gas Analysis	10	A,B,C,D,E	4,3,2,1,0	40
Oil Quality	10	A,C,E	4,2,0	40
Insulation Power Factor	10	A,B,C,D,E	4,3,2,1,0	40
Moisture Content	10	A,B,C,D,E	4,3,2,1,0	40
Main Tank Corrosion	2	A,B,C,D,E	4,3,2,1,0	8
Cooling Equipment	2	A,B,C,D,E	4,3,2,1,0	8
Load History	10	A,B,C,D,E	4,3,2,1,0	40
Bushing Condition	5	A,B,C,D,E	4,3,2,1,0	20
IR Scans	10	A,B,C,D,E	4,3,2,1,0	40
Degree of Polymerization	5	A,B,C,D,E	4,3,2,1,0	20
Grounding	1	A,B,C,D,E	4,3,2,1,0	4
Tap Changer DGA*	6	A,B,C,D,E	4,3,2,1,0	24
Tap Changer Oil Quality*	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				**372**

The health index score for a power transformer is composed of 13 separate condition parameters, with additional two parameters in the case where the asset is equipped with a tap changer. The bulk (two-thirds) of the transformers' total score is attributed to quantitative testing results, with each separate parameter carrying a weight of ten. These measurements include dissolved gas analysis, oil quality, insulation power factor, moisture content, load history, and infrared thermography results. Each of these parameters describe an aspect of a power transformer with a direct impact on the operational health of the asset. Lower scores for one or a combination of these condition parameters strongly indicate progressed degradation of the asset, hence their larger weights. Oil leaks, main tank corrosion, cooling equipment condition, and grounding are collected by visual inspection of a power transformer and serve as indicators of the total health of the asset, although the specific conditions are easily remediated/maintained and have minimal impact on the operational health of the asset if dealt with appropriately and in a timely fashion. Bushing condition, degree of polymerization, and control box condition comprise the condition parameters that carry medium weights to the overall health index score of a power transformer. In the case where a tap changer is integrated with the asset, two additional categories describing the dissolved gas analysis and oil quality of the tap changer are included. These condition parameters capture any operational degradation that may be experienced within a tap changer unit associated with a power transformer asset.

Figure 6.2: Power Transformers condition parameters data availability

Condition Parameter	% of Assets with Data
Overall Condition	100%
DGA	100%
Oil Quality	100%
Degree of Polymerization	100%
IR Scans	100%
Bushings	100%
Main Tank Corrosion	100%
Cooling Equipment	100%
Grounding	100%
Load History	63%
Oil Leaks	100%
Oil Levels	95%
Insulation Power Factor	84%

The data availability for most condition parameters regarding power transformers is relatively high (>84%). The key exception is load history, for which only 63% of the assets in the power transformer class have data, as HOSSM doesn't have SCADA equipment at all stations. The average data availability index across the power transformer asset class is 96%.

Figure 6.3: Health Index distribution for Power Transformers asset class

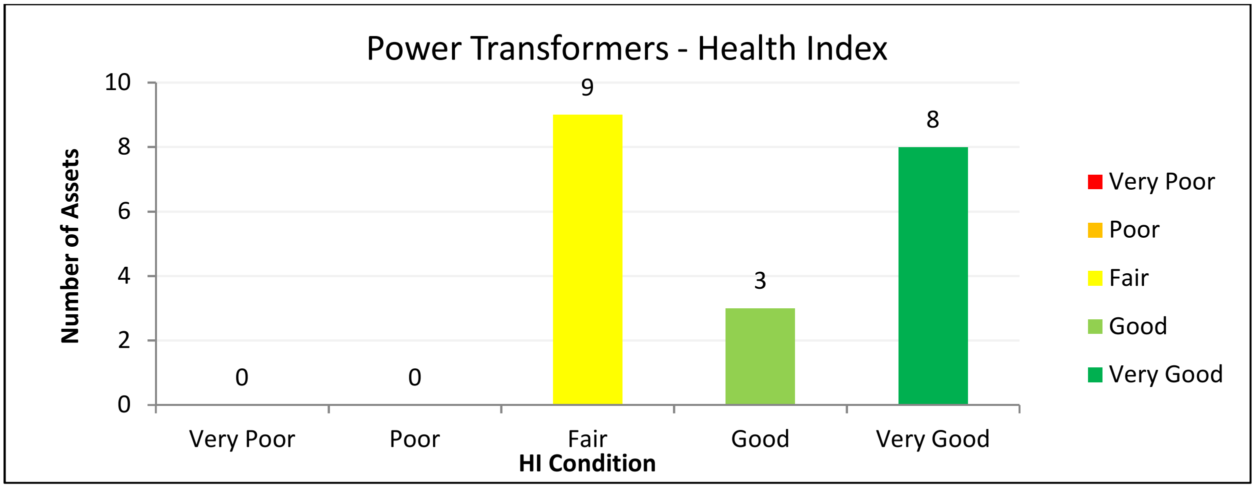
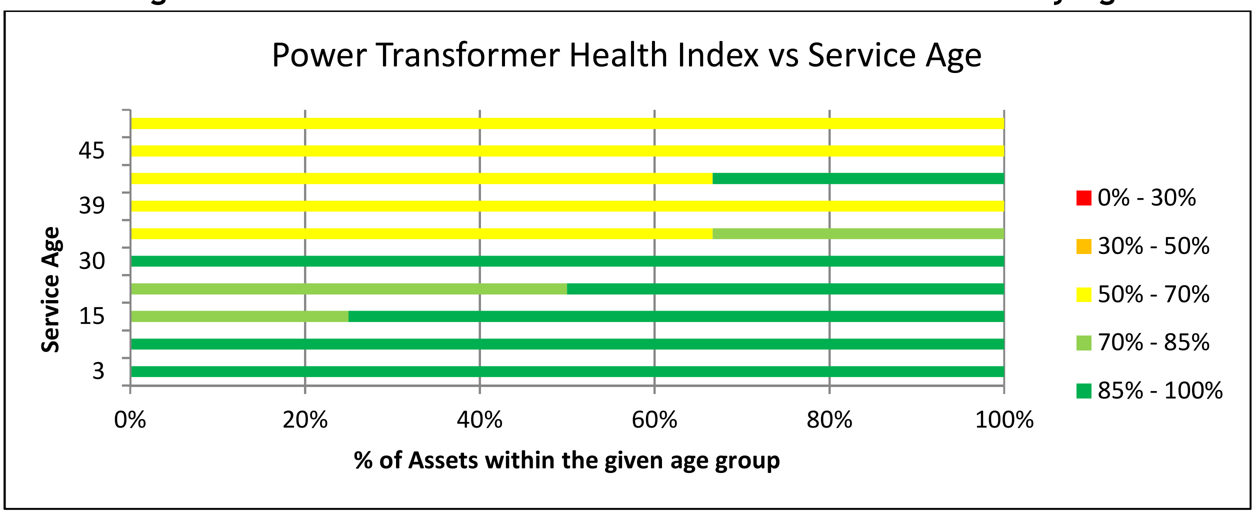


Figure 6.4: Health Index distribution of Power Transformers by Age



There are 20 power transformers (operational and spares) analyzed in the HOSSM system. The average health index for these assets is 74%, which corresponds to a Good condition. There are 8 in Very Good, 3 in Good, and 9 in Fair condition. Of those assets with a Fair rating, the operational units in the worst condition include T2 at Third Line, MT1 and MT2 at Clergue, and T1 at Echo River transmission station. These assets have degraded health index scores due to aging, oil leaks, DGA results, and moisture content as the principal contributing factors.

Figure 6.5: 230/115 kV Autotransformer T1 at Third Line Transmission Station

6.1.2. Circuit Breakers – Vacuum

Figure 6.6: Vacuum Circuit Breakers condition parameter scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Age	30	A,B,C,D,E	4,3,2,1,0	120
Bushing/Support Insulators	4	A,B,C,D,E	4,3,2,1,0	16
Control & Operating Mechanism Components	2	A,B,C,D,E	4,3,2,1,1	8
Overall Condition	4	A,B,C,D,E	4,3,2,1,2	16
Timing/Travel Tests	3	A,B,C,D,E	4,3,2,1,3	12
Infrared Scan (IR)	4	A,C,E	4,2,0	16
Contact Resistance Tests	2	A,B,C,D,E	4,3,2,1,0	8
Non-Discretionary Obsolescence	10	A,E	4,0	40
Enclosure	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				**248**

The health index score for a vacuum circuit breaker is constructed from nine separate condition parameters. For this study, the weight of the age parameter is significant (almost half of the total score) due to the lack of available quantitative measurements of reasonable quality that were made across the asset class.

. Age best approximates the operational degradation of these assets as they progress through their service life. Additionally, asset criteria such as bushing and insulators, overall condition, timing and travel tests, contact resistance tests, and enclosure condition are included where available. In the case where an asset is considered obsolete it is more difficult to find spare and replacement parts to perform maintenance, and so significant weighting is also put into an obsolescence condition parameter.

Figure 6.7: Data availability for Vacuum Circuit Breakers condition parameters

Condition Parameter	% of Assets with Data
Age	100%
Bushing Condition	100%
Overall Condition	94%
Enclosure	81%
Timing/Travel Tests	88%
Control & Operating Mechanism Components	100%
Contact Resistance Tests	88%
Non-Discretionary Obsolescence	100%
IR Scans	100%

Most vacuum circuit breaker condition parameters are available for a large portion of the population. However, enclosure condition and timing and travel tests are available for less than 90% of the units in the asset class. It is recommended that these condition parameters be collected for every asset in the vacuum circuit breaker asset class to further increase the reliability of the health scores going forward. The average data availability index for the vacuum circuit breaker asset class is 95%.

Figure 6.8: Health Index distribution for Vacuum Circuit Breaker asset class

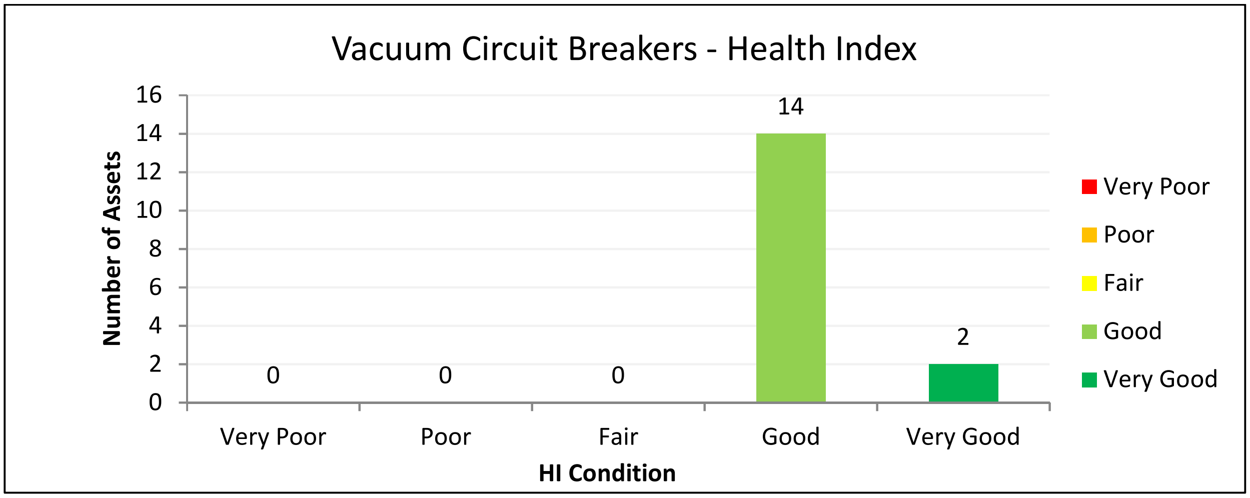
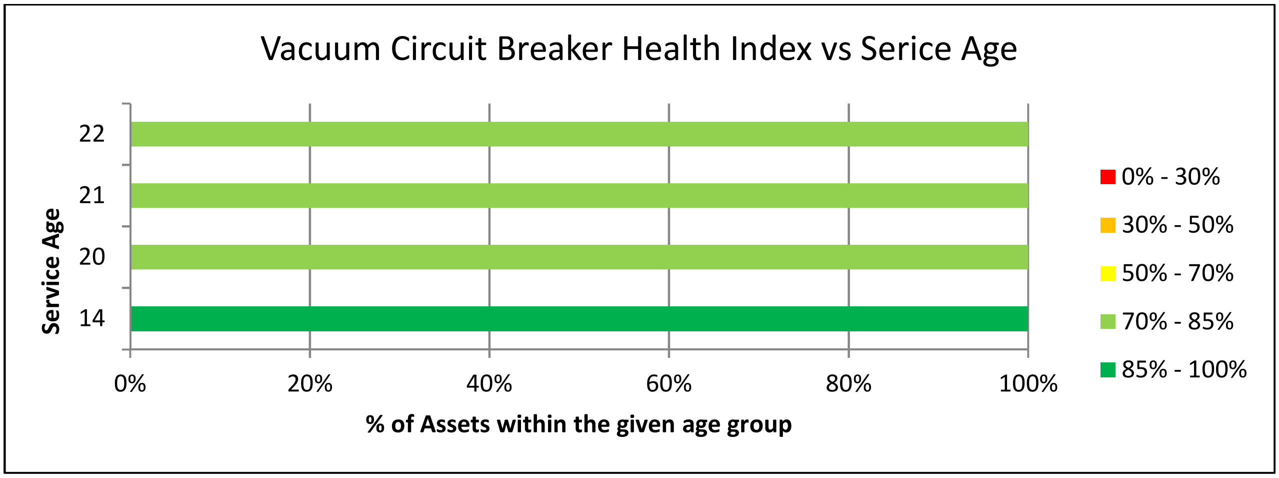


Figure 6.9: Health Index Distribution of Vacuum Circuit Breakers by Age



There are 16 vacuum type circuit breakers evaluated in the HOSSM system. 12 are in Watson, 2 in Hollingsworth, and 2 in Northern Avenue transmission station. The vacuum breakers within Watson and Hollingsworth are in Good condition with an average age of 21 years, whereas those in Northern Avenue are in Very Good condition with an average age of 14 years. The average vacuum circuit breaker health index score class is 76% (Good).

Figure 6.10 Vacuum Circuit Breaker 385 at Northern Avenue Transmission Station

6.1.3. Circuit Breakers – SF6

Figure 6.11: SF6 Circuit Breaker condition parameter scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Age	30	A,B,C,D,E	4,3,2,1,0	120
Bushing/Support Insulators	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	4	A,B,C,D,E	4,3,2,1,2	16
Timing/Travel Tests	3	A,B,C,D,E	4,3,2,1,3	12
Infrared Scan (IR)	4	A,C,E	4,2,0	16
Contact Resistance Tests	2	A,B,C,D,E	4,3,2,1,0	8
Tank and Mechanism Box	4	A,B,C,D,E	4,3,2,1,0	16
Non-Discretionary Obsolescence	10	A,E	4,0	40
SF6 Leaks	4	A,B,C,D,E	4,3,2,1,1	16
Total Score				**260**

The health index score for an SF6 circuit breaker is constructed from nine separate condition parameters. For this study, the weight of the age parameter is significant (almost half of the total score) due to there being a significant lack of quantity and quality of quantitative measurements made across the asset class. Age best approximates the operational degradation of these assets as they progress through their service life. Additionally, asset criteria such as bushing and insulators, overall condition, timing and travel tests, contact resistance tests, and enclosure condition are included where available. In the case where an asset is considered obsolete it is more difficult to find spare and replacement parts to perform maintenance, and so significant weighting is also put into an obsolescence condition parameter. Furthermore, evidence of SF6 leaks can indicate asset degradation and is included for the SF6 circuit breaker asset sub-class.

Figure 6.12: Data Availability for SF6 Circuit Breaker condition parameters

Condition Parameter	% of Assets with Data
Age	100%
Bushing Condition	100%
Overall Condition	88%
Tank & Mechanism Box	97%
Timing/Travel Tests	58%
Contact Resistance Tests	45%

Non-Discretionary Obsolescence	100%
SF6 Gas Leak	90%
IR Scans	92%

Most SF6 circuit breaker condition parameters are available for a large portion of the population. However, contact resistance and timing and travel tests are available for less than 58% of the units in the asset class. It is recommended that these condition parameters be collected for every asset in the SF6 circuit breaker asset class to further increase the reliability of the health scores going forward. The average data availability index for the vacuum circuit breaker asset class is 86%.

Figure 6.13: Health Index Distribution for SF6 Circuit Breaker asset class

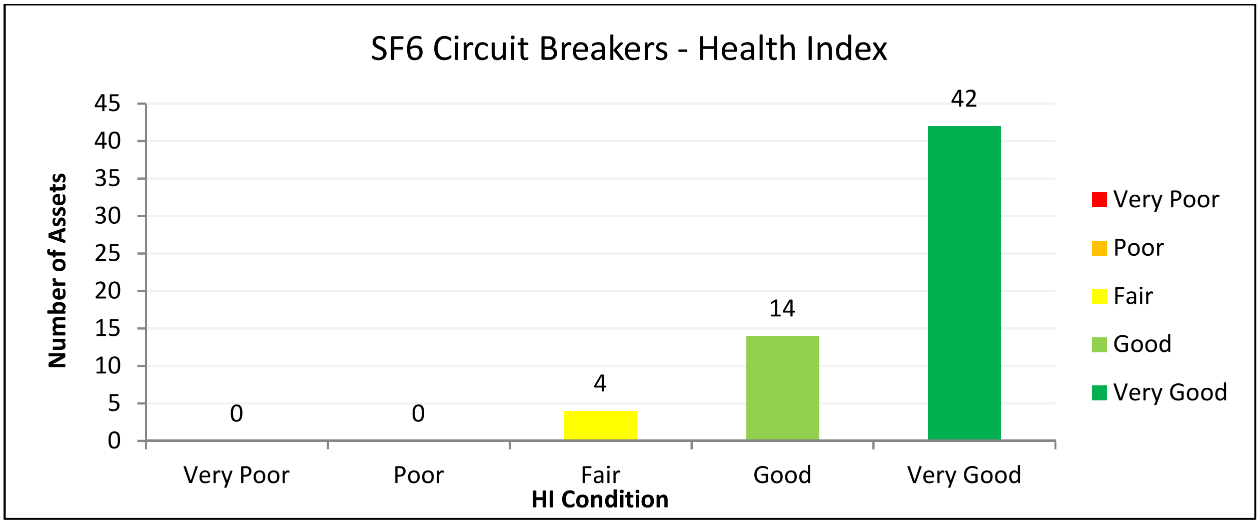
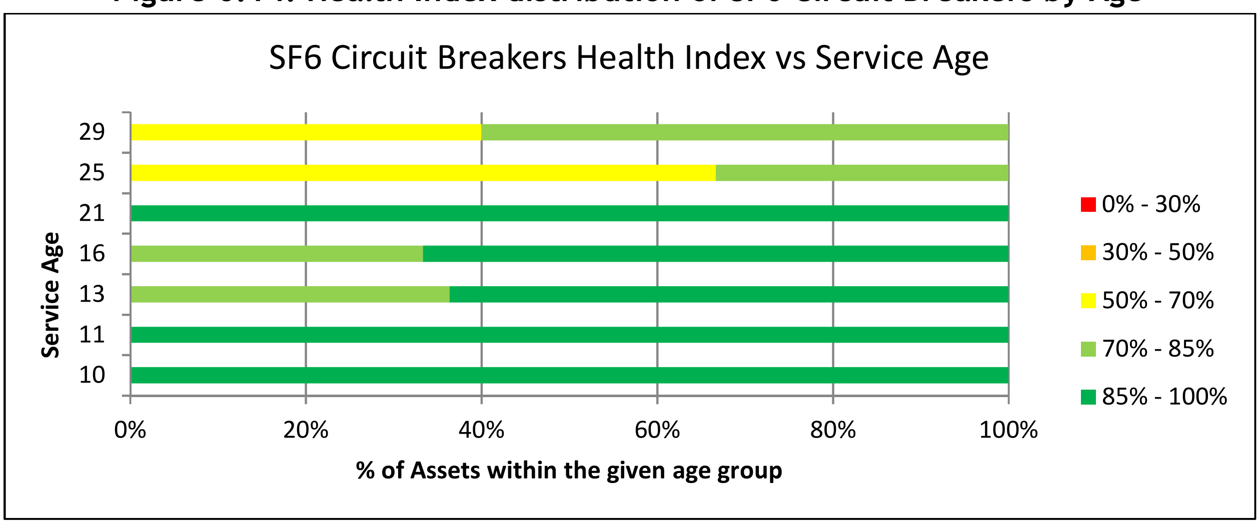


Figure 6.14: Health Index distribution of SF6 Circuit Breakers by Age



Sixty SF6 type circuit breakers were analyzed within the HOSSM system for this report. Across the asset class, the average health index was 89%, which corresponds to a Very Good condition rating. The assets with the lowest scores (Fair) are older units (>25 years of age) from Anjigami, Clergue, Steelton, and Magpie transmission stations. 46 of the 60 assets in the class were installed within the past 13 years, with a significant portion of those newer units being attributed to the breaker-and-a-half overhaul at Third Line transmission station in 2008.

Figure 6.15: SF6 Circuit Breaker 1613 at Third Line Transmission Station

6.1.4. Circuit Breakers – Oil

Figure 6.16: Oil Circuit Breaker condition parameter scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Age	30	A,B,C,D,E	4,3,2,1,0	120
Bushing/Support Insulators	4	A,B,C,D,E	4,3,2,1,0	16
Control & Operating Mechanism Components	2	A,B,C,D,E	4,3,2,1,1	8
Overall Condition	4	A,B,C,D,E	4,3,2,1,2	16
Timing/Travel Tests	3	A,B,C,D,E	4,3,2,1,3	12

Infrared Scan (IR)	4	A,C,E	4,2,0	16
Contact Resistance Tests	4	A,B,C,D,E	4,3,2,1,0	16
Tank and Mechanism Box	4	A,B,C,D,E	4,3,2,1,0	16
Oil Leaks	2	A,B,C,D,E	4,3,2,1,0	8
Non-Discretionary Obsolescence	10	A,E	4,0	40
Oil Analysis Tests	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				**276**

The health index score for a minimum oil circuit breaker is constructed from 11 separate condition parameters. For this study, the weight of the age parameter is significant (almost half of the total score) due to there being a significant lack of quantity and quality of quantitative measurements made across the asset class, based on HOSSM's current practices. Age best approximates the operational degradation of these assets as they progress through their service life. Additionally, asset criteria such as bushing and insulators, overall condition, timing and travel tests, contact resistance tests, and enclosure condition are included where available. In the case where an asset is considered obsolete it is more difficult to find spare and replacement parts to perform maintenance, and so significant weighting is also put into an obsolescence condition parameter. Where available oil analysis tests and evidence of oil leaks/refills are included as condition parameters as they indicate a possible area of degradation for minimum oil circuit breakers.

Figure 6.17: Data availability for Oil Circuit Breaker condition parameters

Condition Parameter	% of Assets with Data
Age	100%
Bushing Condition	100%
Overall Condition	100%
Tank & Mechanism Box	89%
Timing/Travel Tests	95%
Control & Operating Mechanism Components	84%
Contact Resistance Tests	89%
IR Scans	100%
Oil Leaks	100%
Non-Discretionary Obsolescence	100%
Oil Analysis	79%

Most oil circuit breaker condition parameters are available for a large portion of the population. However, operating mechanism condition and oil analysis testing results are available for less than 85% of the units in the asset class. It is recommended that these condition parameters be collected for every asset in the oil circuit breaker asset class to further increase the reliability of the health scores going forward. The average data availability index for the vacuum circuit breaker asset class is 94%.

Figure 6.18: Health Index distribution for Oil Circuit Breaker asset class

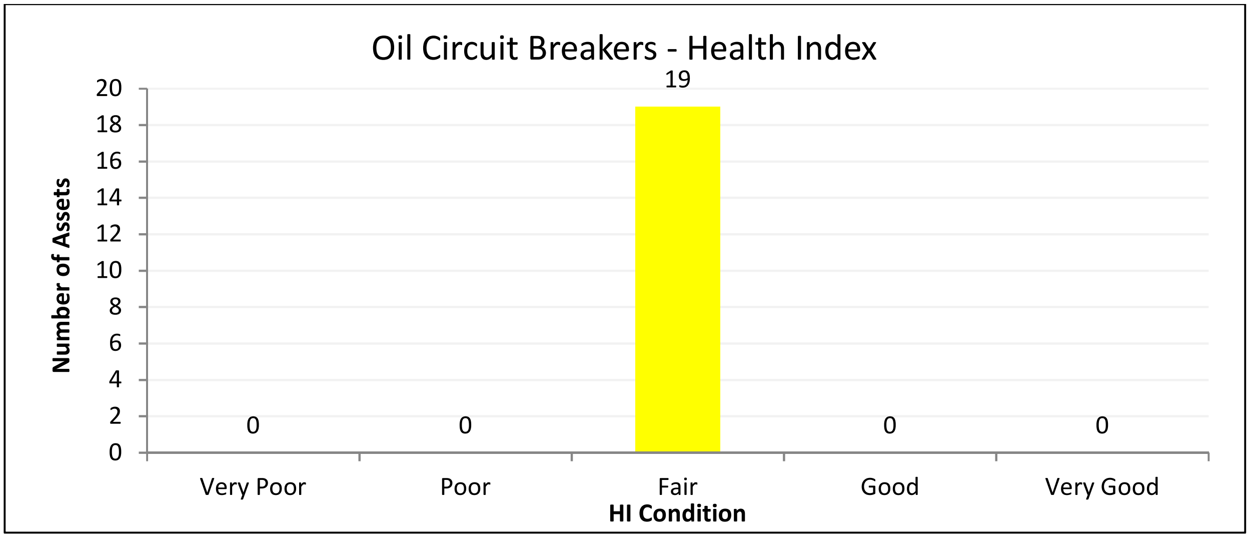
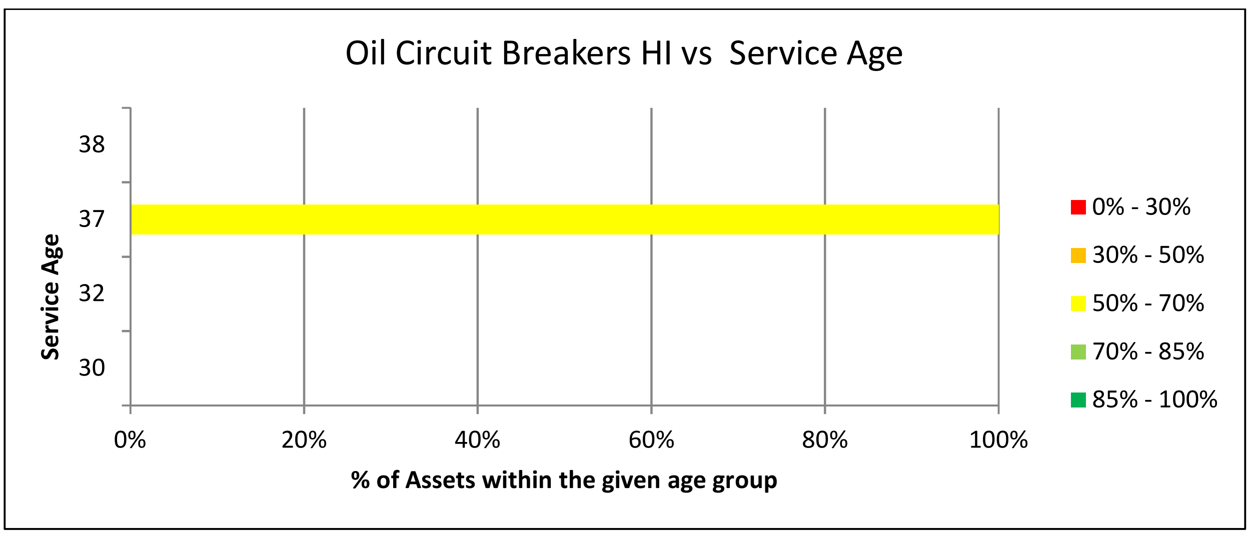


Figure 6.19: Heath Index distribution if Oil Circuit Breakers by Age



There are 19 minimum oil circuit breakers in the HOSSM system. The average health index for these assets is 54% and all the breakers are in Fair condition. The main contributor to these breakers lower health score is twofold. The first being that these units are significantly progressed in their useful economic life with an average age of 37 years. Furthermore, the oil type circuit breakers at the Clergue transmission station are considered obsolete by the manufacturer (Sprecher and Schuh make, HPTW 304 g type).

Figure 6.20: **Oil Circuit Breaker 211 at Steelton Transmission Station**

6.1.5. Instrument Transformers

Figure 6.21: Instrument Transformer condition parameter scoring table

Condition	Type	Weight	Ranking	Numerical Grade	Max Grade
Age	PT/CVT	20	A, B, C, D, E	4, 3, 2, 1, 0	80
Overall Condition	PT/CVT	3	A, B, C, D, E	4, 3, 2, 1, 1	12
Bushings	PT/CVT	3	A, B, C, D, E	4, 3, 2, 1, 2	12
Main Tank Oil Leaks	PT	4	A, B, C, D, E	4, 3, 2, 1, 3	16
	CVT	6	A, B, C, D, E	4, 3, 2, 1, 4	24
Condition of Foundation, Support Steel and Grounding	PT/CVT	2	A, B, C, D, E	4, 3, 2, 1, 5	8
Tank and terminal box condition grading	PT	2	A, B, C, D, E	4, 3, 2, 1, 6	8

	CVT	3	A, B, C, D, E	4, 3, 2, 1, 7	12
IR Scans	PT/CVT	3	A, B, C, D, E	4, 3, 2, 1, 8	12
Total Score				**PT**	**148**
				CVT	**160**

Within the class of instrument transformers, Potential Transformers (PTs) and Capacitor Voltage Transformers (CVTs) are included. The total health index score for an instrument transformer is composed of seven separate condition parameters. Bushing condition, main tank oil leaks, foundation condition, support steel and grounding, and terminal box condition are weighted relatively lightly due to their qualitative nature. Infrared thermography scans and age of the asset were the only quantitative measurements made during the assessment of the instrument transformers in the HOSSM system. Therefore, the age condition parameter is scaled up and represents half of the total weight of an asset health index score, as per the above table. This acts a proxy for objective quantitative condition parameters that would ideally account for most of the total score for each asset belonging to the instrument transformer class.

Figure 6.22: Data Availability for Instrument Transformer condition parameters

Condition Parameter	% of Assets with Data
Age	100%
Bushings	97%
Main Tank Oil Leaks	80%
Condition of Foundation, Support Steel and Grounding	98%
Tank and terminal box condition grading	86%
IR Scans	93%
Overall Condition	81%

Most instrument transformer condition parameters are available for at least 80% of the asset population. However, details regarding main tank oil leaks are available for only 80% of the units in the asset class. It is likely the case that leaks are not reported for assets that are not exhibiting major leaks requiring maintenance or correction. The average data availability index for the circuit switcher asset class is 91%.

Figure 6.23: Health Index distribution for Instrument Transformer asset class

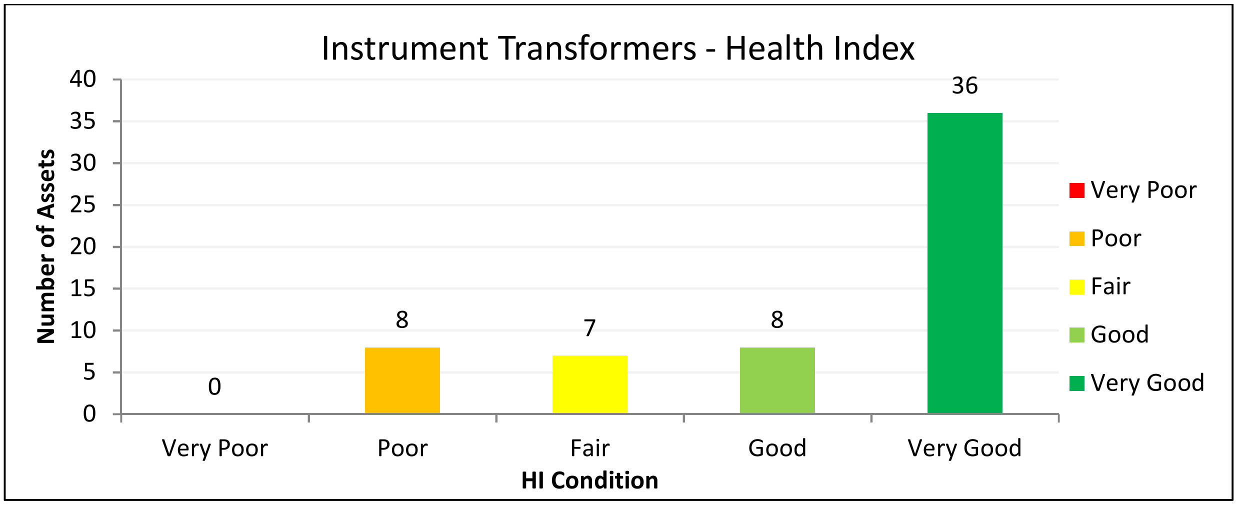
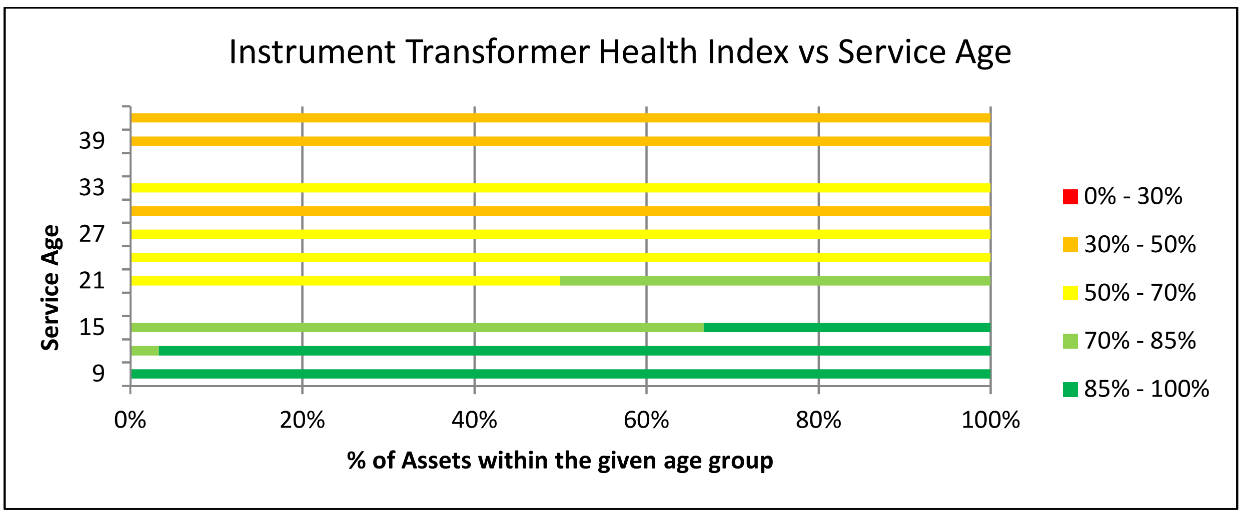


Figure 6.24: Health Index distribution of Instrument Transformers by Age



Considered in the asset class of Instrument Transformers are Capacitor Voltage Transformers (CVTs) and Potential Transformers (PTs). Seventeen PTs and 42 CVTs were analyzed by METSCO and assigned a health index score. The average score for the Instrument Transformers is 77%, which corresponds to being in Good condition. There are 3 oil type PTs in Clergue station and a PT in Anjigami TS, each receiving a score of 50% or lower, which is much lower than the class average. The primary driver for these lower scores is the advanced age of these units, with each of them being 38 years or older.

6.1.6. Batteries

Figure 6.25: Battery condition parameter scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Age of Battery Bank	4	A,B,C,D,E	4,3,2,1,0	16
Testing (Storage Capacity)	4	A,C,E	4,2,0	16
Total Score				**32**

The battery bank health index score is comprised of two condition parameters with equivalent weightings. The first condition parameter is age, which provides insight on the remaining useful life of the asset based on typical lifetimes of DC systems seen across industry. Batteries also operate based on a determinate chemical process, which has a known lifetime and useful duration. Discharge testing provides detail on individual cell charge, total voltage, and discharge rates as the battery supplies energy over time. Any atypical degradation of a battery banks performance will be seen in this type of comprehensive testing procedure. By building the health index score from these two parameters, static and dynamic effects on a batteries remaining life can be classified.

Figure 6.26: Data availability for Battery condition parameters

Condition Parameter	% of Assets with Data
Age	100%
Battery Load/Capacity Test	100%

Age and testing data was available for all of the 22 station battery banks that were evaluated in the study. The average data availability for these assets is therefore 100%. The results of our assessment are provided on the following page.

Figure 6.27: Health Index distribution for Battery asset class

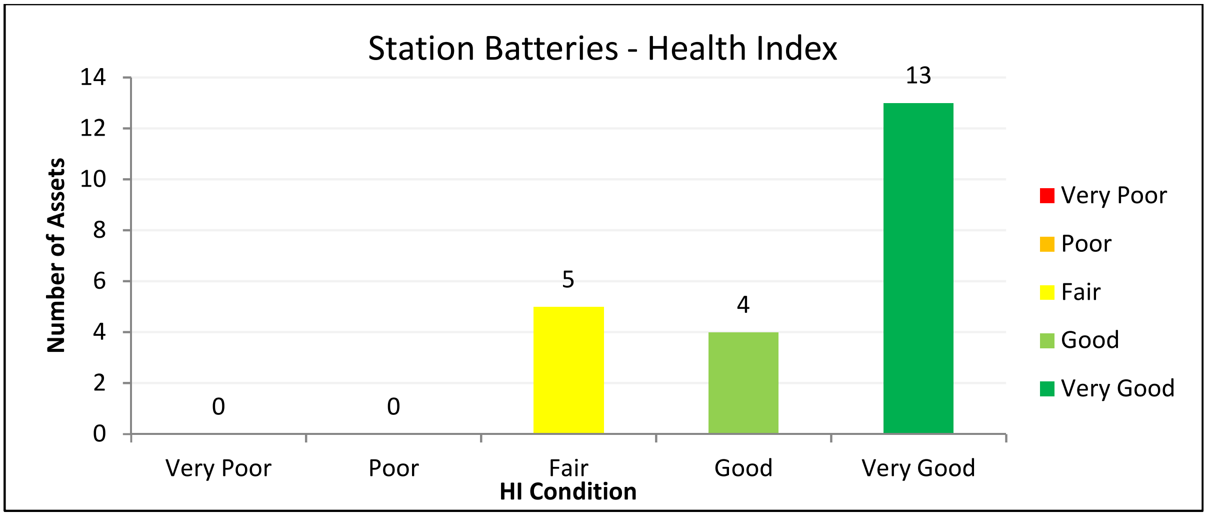
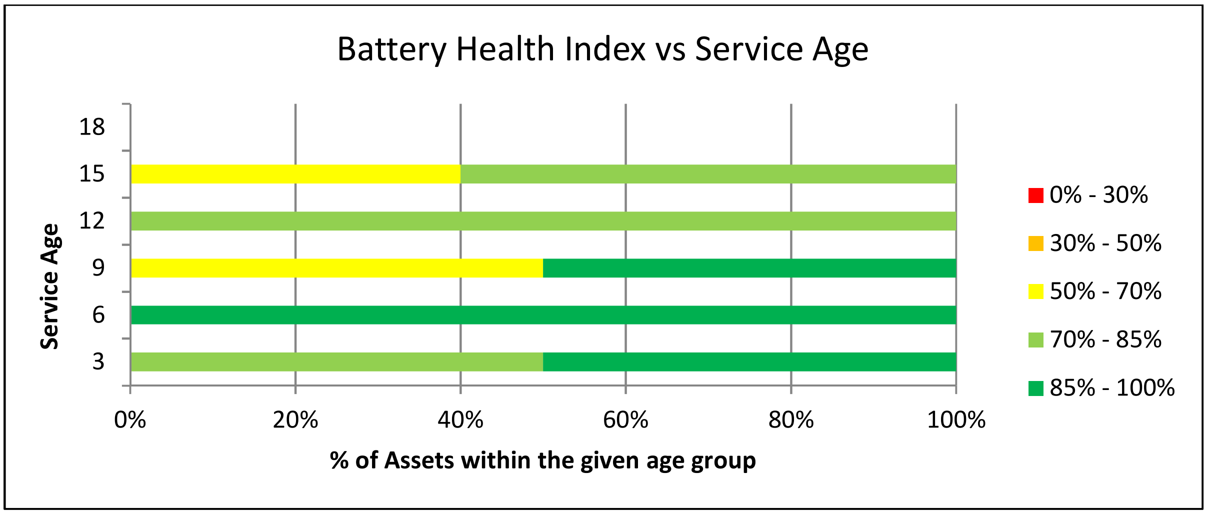


Figure 6.28: Health Index distribution of Batteries by age



Batteries are separated into two categories/types, vented and non-vented. Vented batteries are assumed to have a longer useful life of 20 years, whereas non-vented batteries have an expected useful life of 10 years [1]. There are 9 vented and 13 non-vented battery banks analyzed across the HOSSM system. The non-vented batteries were mostly in Very Good condition, with three being in Fair condition. The vented batteries had 3 units in Very Good condition, 4 in Good condition and 2 in Fair condition. The average health index score of the battery bank class is 83% (Good).

[1] Facilities Instructions, Standard, and Techniques Volume 3-6: Storage Battery Maintenance and Principles. U.S. Department of the Interior Bureau of Reclamation. 2016. https://www.usbr.gov/power/data/fist/fist3_6/FIST_3-6_010617.pdf.

Figure 6.29 Vented-type Battery Bank 'B' at Third Line Transmission Station

6.1.7. Switches

Figure 6.30: Switches condition parameter scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Condition of Switch/Disconnect Blades and Contacts	4	A,B,C,D,E	4,3,2,1,0	16
Power Train Drive Assembly	4	A,B,C,D,E	4,3,2,1,0	16
Connectors and Conductors	3	A,B,C,D,E	4,3,2,1,0	12
Contact Resistance Test	3	A,B,C,D,E	4,3,2,1,0	12
Insulators/Porcelains	3	A,B,C,D,E	4,3,2,1,0	12
Foundation/Support Steel/Grounding	3	A,B,C,D,E	4,3,2,1,0	12
Total Score				**80**

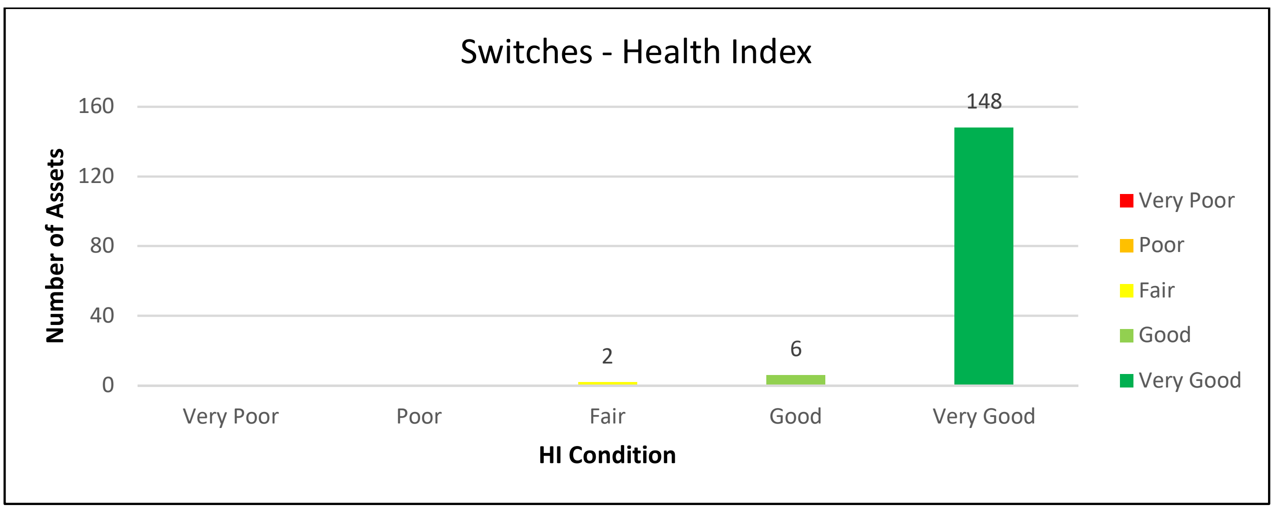
The total health index score for a switch is composed of six separate condition parameters. The most significant weights belong to the condition parameters describing the contacts of the switch as well as the drive train assembly, as these two parameters succinctly describe the operational health of the asset. The contact resistance test quantitively assesses the degradation of the switch contacts and the ability for the asset to efficiently transmit energy. Connectors and conductors, insulators, structure/supports, and grounding condition parameters are equally weighted condition criteria and compose the latter half of the total health score for switches. These are the qualitative visual inspection criteria that further describe the overall health of the asset.

Figure 6.31: Data availability for Switches condition parameters

Condition Parameter	% of Assets with Data
Condition of Switch/Disconnect Blades and Contacts	91%
Connectors and Conductors	52%
Insulators/Porcelains	85%
Foundation/Support Steel/Grounding	69%
Contact Resistance Test	51%
Power Train Drive Assembly	95%

The average data availability index for switch condition parameters is 74%. Lacking are connector and conductor condition (52%) and contact resistance test (51%). It is recommended that these conditions be captured going forward in the asset management program for switches at HOSSM.

Figure 6.32: Health Index distribution for Switches asset class



A health index for 156 switch class assets was generated, with an average health index of 97%, which corresponds to a Very Good condition rating. There are 148 assets in Very Good, 6 in Good, and 2 in Fair condition. The units with lower scores are associated to situations where there is some combination of advanced corrosion, bushing degradation, and/or contact misalignment.

Figure 6.33: Overhead Disconnect Switch 203 at Steelton Transmission Station

6.1.8. Protection Relays

Figure 6.34: Relay condition parameter scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Visual Inspection	3	A,B,C,D,E	4,3,2,1,0	12
Defect and Test Reports	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Non-Discretionary Obsolescence	5	A,E	4,0	20
Discretionary Obsolescence	1	A,B,C,D,E	4,3,2,1,0	4
Total Score				**68**

The health index score for a relay is composed of five separate condition parameters. To properly measure functional capability, defect and test reports are collected and analyzed. Any physical degradation or system level integration issues regarding the asset is accounted for within a visual inspection condition parameter. The age of the asset is recorded and compared to an industry standard typical useful life for the specific relay type, and a service age condition score is calculated. Non-Discretionary obsolescence is the inability to procure spares or support from the manufacturer, indicating a truly obsolete piece of equipment. This type of obsolescence is the most significant driver for relay replacement, and thus carries the heftiest weight. Discretionary obsolescence is a descriptor of the means for a utility to replace relay assets of a certain type based on preference and to simplify overall system design. An asset may be flagged as discretionally obsolete based on requirements of the utility's replacement program, a system wide transition to a newer relay model, or some other preferentially based reasoning. Although important for system design and overall system health, this does not necessarily reflect degradation of the assets functionality for its designed purpose and thus carries the lowest weight for determining the total health score.

Figure 6.35: Data availability for Relay condition parameters

Condition Parameter	% of Assets with Data
Service Age	96%
Defect and Test Report	36%
Visual Inspection	19%
Non-Discretionary Obsolescence	98%
Discretionary Obsolescence	98%

The average data availability for a relay's condition parameters in the HOSSM system is 69%. This is the lowest across all asset classes. This is due to the severe lack of visual inspection (19%) and test reports (36%) for these assets. It is recommended that these conditions be captured going forward in the asset management program for relays at HOSSM.

Figure 6.36: Health Index Distribution for Relay asset class

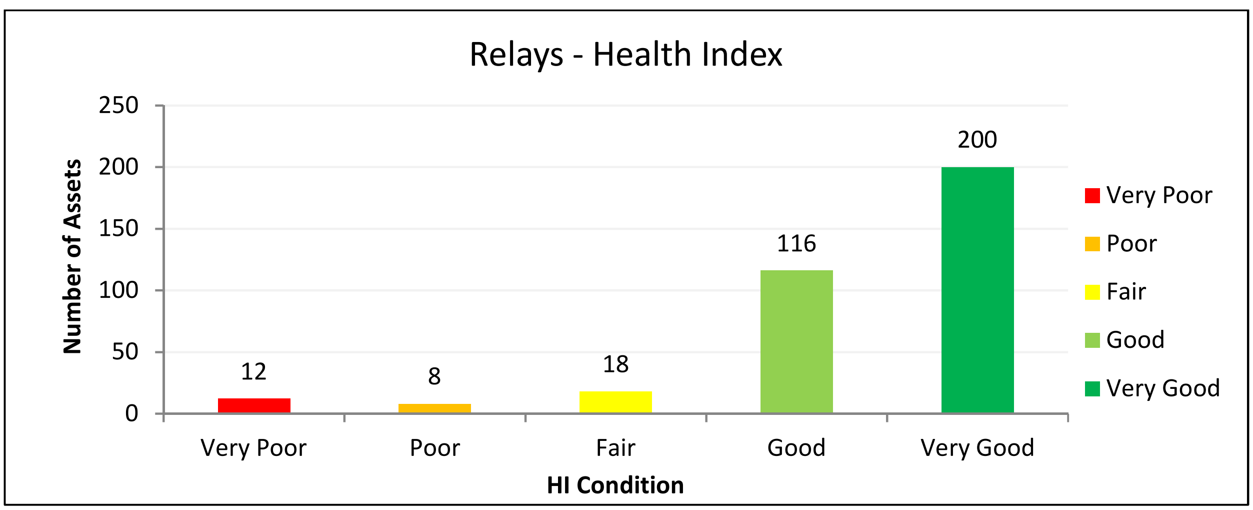
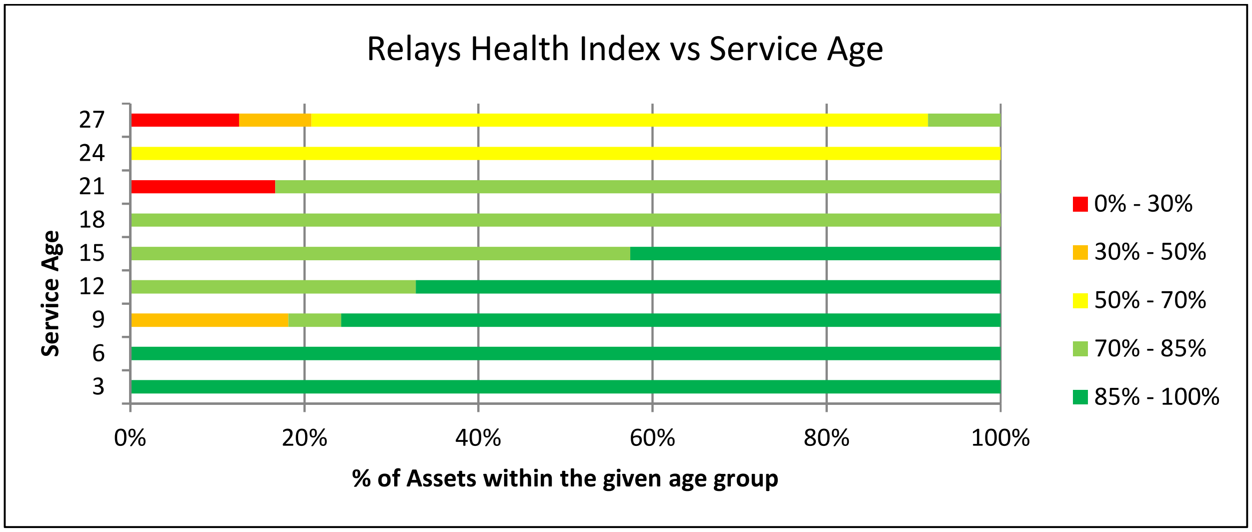


Figure 6.37: Health Index Distribution of Relays by Age



METSCO analyzed 359 Relay assets were analyzed in the HOSSM system. The average health index for Relays is 81%. There are 200 in Very Good, 116 in Good, 18 in Fair, 8 in Poor, and 12 in Very Poor condition. A health index for seven units was unable to be formulated due to a lack of data. The primary drivers for units with lower health index scores were their significantly progressed age, or obsolescence of the specific relay type (i.e. Alstom - KCEG relays).

Figure 6.38: Electronic Relay Cabinets at Mackay Transmission Station

6.1.9. Circuit Switchers

Figure 6.39: Circuit Switchers condition parameters scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Insulators/Porcelains	3	A,B,C,D,E	4,3,2,1,0	12
Drive Train Assembly	4	A,B,C,D,E	4,3,2,1,0	16
Motor Operator and Controls	3	A,B,C,D,E	4,3,2,1,0	12
Disconnect Live Parts	3	A,B,C,D,E	4,3,2,1,0	12
Connectors and Conductors	3	A,B,C,D,E	4,3,2,1,0	12
Foundation/Support Steel/Grounding	3	A,B,C,D,E	4,3,2,1,0	12
Contact Resistance	3	A,B,C,D,E	4,3,2,1,0	12
Infrared Scan (IR)	6	A,C,E	4,2,0	24
SF6 Leaks and Severity	6	A,C,E	4,2,0	24
Total Score				**136**

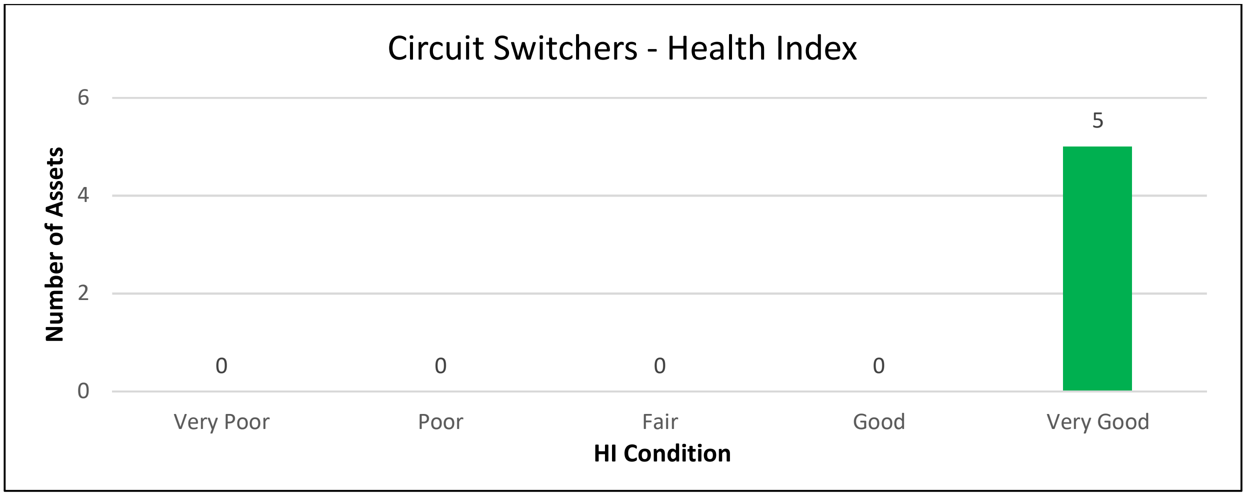
The health index for circuit switchers is composed of nine separate condition parameters. Infrared scanning and SF6 leakage carry the highest weights, since these conditions point to in-service degradation. Insulators, connectors and conductors, foundations, support steel, grounding, and contact resistance testing can confirm the appropriate mechanical and electrical operational health of a circuit switcher. Finally, the health of the drive train assembly and motor controls capture the critical qualities for proper opening and closing of the asset when it is in use. Degradation in any of the parameters indicates a lower total health index score for assets belonging to the circuit switcher class.

Figure 6.40: Data availability for Circuit Switcher condition parameters

Condition Parameter	% of Assets with Data
IR Scan	100%
Contact Resistance	80%
SF6 Leaks	40%
Foundation/Support/Grounding	80%
Connectors and Conductors	80%
Disconnect Live Parts	80%
Motor Operated Controls	80%
Drive Train Assembly	80%
Insulators / Porcelains	80%

Most circuit switcher condition parameters are available for at least 80% of the asset population. However, details regarding SF6 leaks are available for only 40% of the units in the asset class. It is likely the case that leaks are not reported for assets that are not exhibiting major leaks requiring maintenance or correction. The average data availability index for the circuit switcher asset class is 78%.

Figure 6.41: Health Index distribution for Circuit Switcher asset class



Five circuit switchers from the HOSSM system were evaluated and assigned a health index. Two are in Batchawana, two are in Goulais, and the last analyzed asset is in the Echo River transmissions station. All the assets in the circuit switcher class have health indices greater than 88%, with an asset class average of 95%, which corresponds to a Very Good condition rating.

Figure 6.42: Circuit Switcher 598 at Batchawana Transmission Station

6.1.10. Capacitors

Figure 6.43: Capacitor condition parameters scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Age	6	A,B,C,D,E	4,3,2,1,0	24
Capacitor Units	4	A,B,C,D,E	4,3,2,1,0	16
Connectors and Conductors	1	A,B,C,D,E	4,3,2,1,0	4
Steel Mounting Structure	1	A,B,C,D,E	4,3,2,1,0	4
IR Thermography Results	3	A,B,C,D,E	4,3,2,1,0	12
Doble and Capacitance Tests	3	A,B,C,D,E	4,3,2,1,0	12
Support Insulators	2	A,B,C,D,E	4,3,2,1,0	8
Overall Shunt Capacitor Bank Condition	3	A,B,C,D,E	4,3,2,1,0	12
Bushings and Insulators	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				**100**

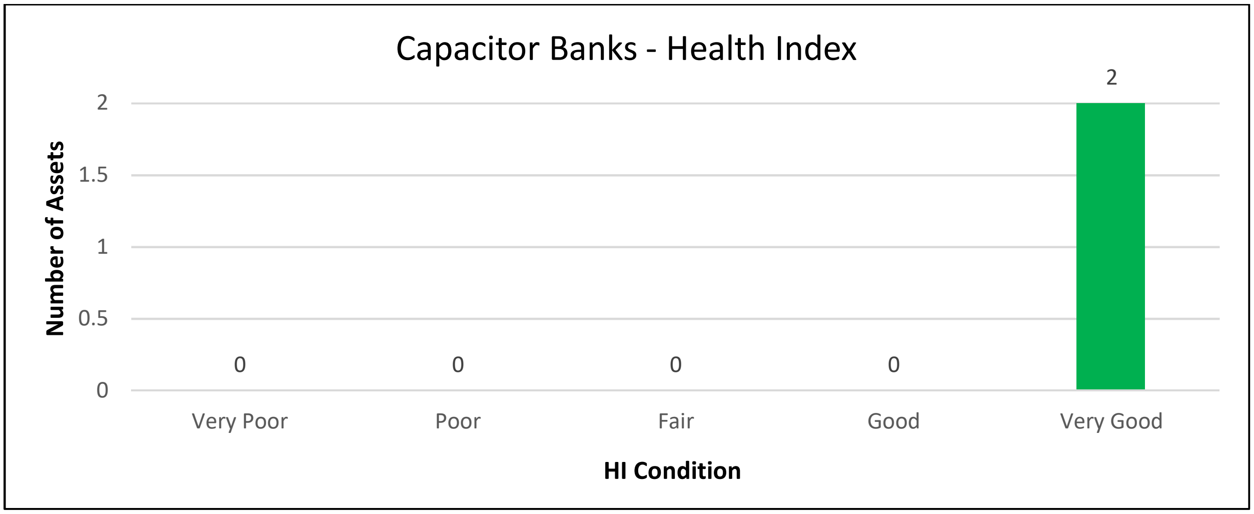
A health index for a station shunt capacitor bank is constructed from nine condition parameters. The largest portion goes to age of the asset, which is mapped to a typical useful life within the asset class observed in industry. Capacitors are also oil filled units, and the oil contained within these units has a limited lifetime because it does not get reconditioned. Less critical to a capacitors unit's health index are connector, mounting structure, and support insulator conditions, which are less reflective of the total asset health itself. Infrared thermography, Doble testing, and capacitance testing map directly to the operational strength of a capacitor-type asset and deficiencies in these condition parameters reflect a more severe degradation of the asset which is reflected in their higher relative parameter weightings.

Figure 6.44: Data Availability for Capacitor condition parameters

Condition Parameter	% of Assets with Data
Age	100%
Capacitor Units	100%
IR Thermography Results	100%
Doble and Capacitance Tests	100%
Overall Capacitor Bank Conditions	100%
Bushings and Insulators	100%

All of the condition parameters for capacitor banks were collected for both of the assets in the HOSSM system. Therefore the data availability index for this asset class is 100%.

Figure 6.45: Health Index distribution for Capacitor asset class



Both capacitors in the HOSSM system (C4, C5) are located within the Third Line transmission station. C4 and C5 have a health index of 94% (Very Good), based on age, visual inspection, and on-site measurements made during prior maintenance operations.

Figure 6.46: Capacitor Bank #5 at Third Line Transmission Station

6.1.11. Reactors

Figure 6.47: Reactor condition parameter scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Bushing Condition	1	A,B,C,D,E	4,3,2,1,0	4
Main Tank	1	A,B,C,D,E	4,3,2,1,2	4
Foundation/Support Steel/Grounding	1	A,B,C,D,E	4,3,2,1,5	4
Overall Reactor Condition	2	A,B,C,D,E	4,3,2,1,6	8
Age	4	A,B,C,D,E	4,3,2,1,8	16
Winding Doble Test	4	A,B,C,D,E	4,3,2,1,9	16
Total Score				**52**

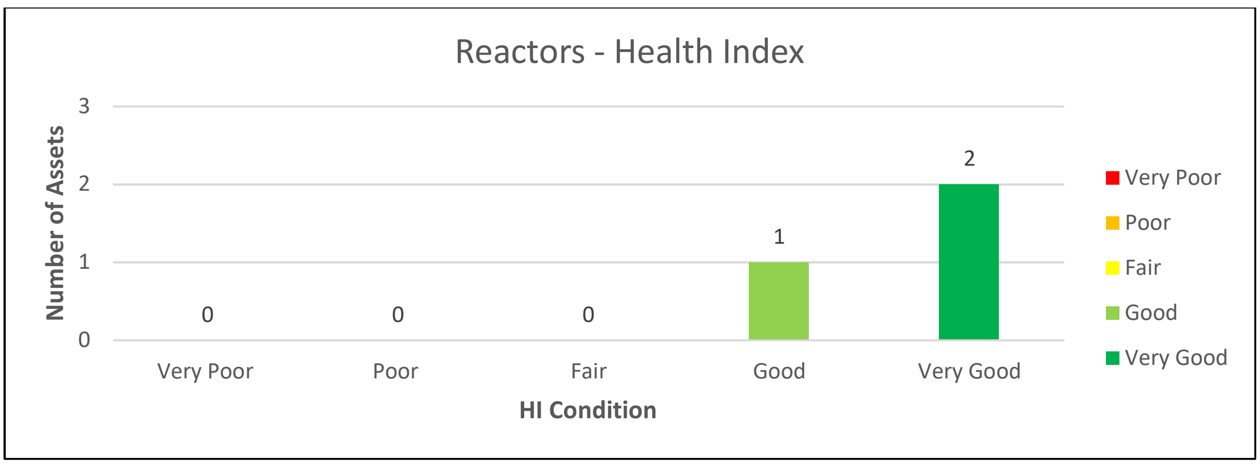
A health index for a station reactor is composed of six condition parameters. The two most important and therefore heavily weighted condition parameters are asset age and Doble testing. Age of an asset acts as a metric for determining the expected remaining useful life based on similar reactor assets across industry. The Doble test, performed on the windings of the reactor, will reflect changes in the operational performance of the asset. Additionally, external factors such as bushing condition, main tank condition, foundations, support steel, and grounding further indicate the degradation of a reactor.

Figure 6.48: Data Availability for Reactor condition Parameters

Condition Parameter	% of Assets with Data
Age	100%
Bushing Condition	100%
Main Tank / Cabinet Controls	100%
Foundational / Support Steel / Grounding	100%
Overall Reactor Condition	100%
Doble Test	33%

Every condition parameter is captured for every reactor, except for Doble testing. This testing was only performed on reactor R4 in the Third Line transmission station. It is recommended that this testing be performed on every asset in the reactor asset class to further increase the reliability of the health scores going forward. The average data availability index for the reactor asset class is 89%.

Figure 6.49: Health Index distribution for Reactor asset class



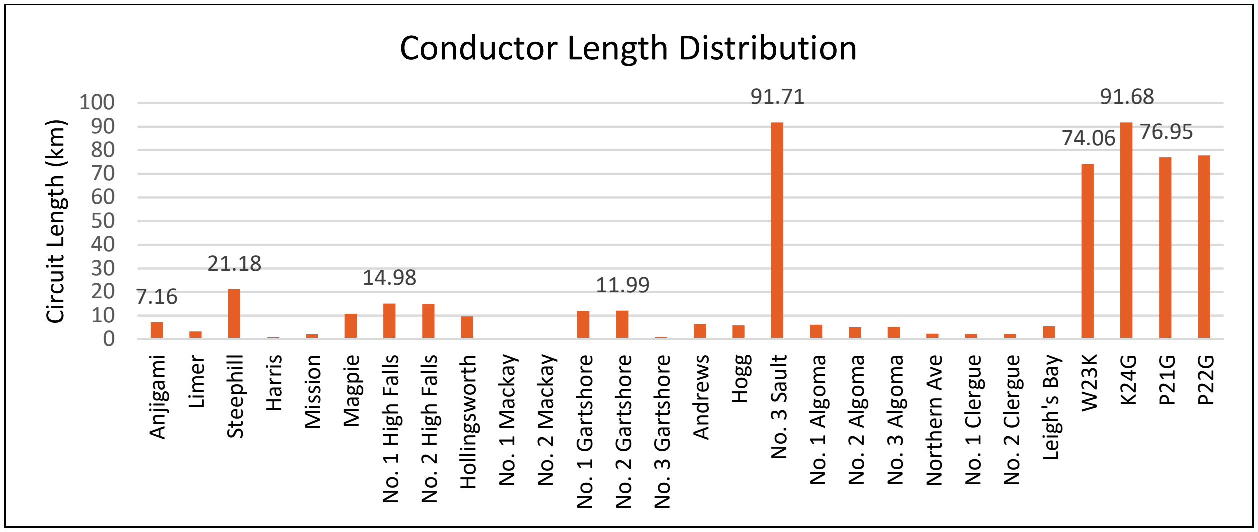
There are 3 reactors in the HOSSM system. Two are in the Third Line transmission station and one is in the Mackay transmission station. These reactors are part of the tertiary connections for the three largest power transformers in the system (in terms of capacity and loading). R1 in Mackay transmission station was visually inspected separately by METSCO during a site visit and received a health index score of 83% (Good). The remaining two reactors at Third Line transmission station are both in Very Good Condition. The average health index for this class is 88%, which corresponds to a Very Good asset condition.

Figure 6.50: **Air-core Shunt Reactor R1 at Mackay Transmission Station**

6.1.12. Line Conductor

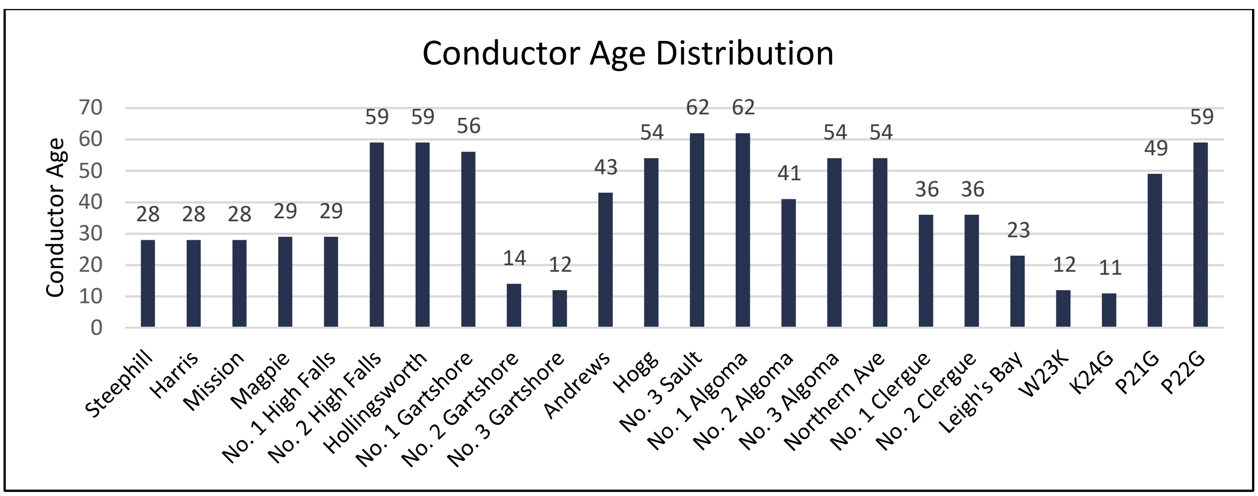
Of all major asset classes, conductor was the one class where METSCO faced the most significant data limitations to complete its assessment, since HOSSM does not regularly test its conductor through a preventative maintenance program. Available data was procured from a study done by Kinectrics in 2015, which investigated the repetitive sleeve failures along the conductor comprising the Sault No. 3 circuit. It was determined that between 2013 and 2015 the Sault No. 3 conductor had experienced three sleeves failures that required the conductor to be removed from service for emergency maintenance and repair. The possible reasons for these sleeve failures include: advanced corrosion to the conductor due to ingress of water during winter icing, inner contaminant material disrupting electrical connections, and incorrect installation/crimping placement along the sleeve length.

Figure 6.51: Circuit Length Distribution of the HOSSM System



Discussion with the HOSSM staff indicated that these types of failures have become more frequent in the past five years. The Sault No. 3 circuit itself accounts for 16.3% of the total length of conductor in the transmission system, and services the 115 kV "backbone" connection extending between Third Line and Mackay transmission station. Based on these findings, the entire Sault No. 3 circuit was given a condition score of 30%, which corresponds to a Poor condition rating. Any further degradation of the circuit would result in the asset being de-rated further to Very Poor.

Figure 6.52: Conductor Age Distribution by Circuit



Nine of the 28 circuits in the transmission system have conductor that is over 50 years of age. This corresponds to 40% of the total conductor length in the system being past this age threshold. The average age of the circuits in the system is 39 years. These circuits have little to no reliability or historical failure information. Based on these considerations the remaining conductor in the system is given a health score of 80%, which corresponds to a Good condition rating. When the entirety of the conductor asset in the system is evaluated together, the average score is 71%, which corresponds to a Good condition rating.

6.1.13. Transmission Line Support Structures

Figure 6.53: Structures condition parameter scoring table

Condition	Weight	Ranking	Numerical Grade	Max Grade
Cross arm Condition	8	A,B,C,D,E	4,3,2,1,0	32
Pole/Structure Condition	10	A,B,C,D,E	4,3,2,1,0	40
Insulator Condition	7	A,B,C,D,E	4,3,2,1,0	28
Grounding	4	A,C,D,E	4,2,1,0	16
Guy Condition	3	A,C,D,E	4,2,1,0	12
Guy Anchor	5	A,C,D,E	4,2,1,0	20
Total Score				**148**

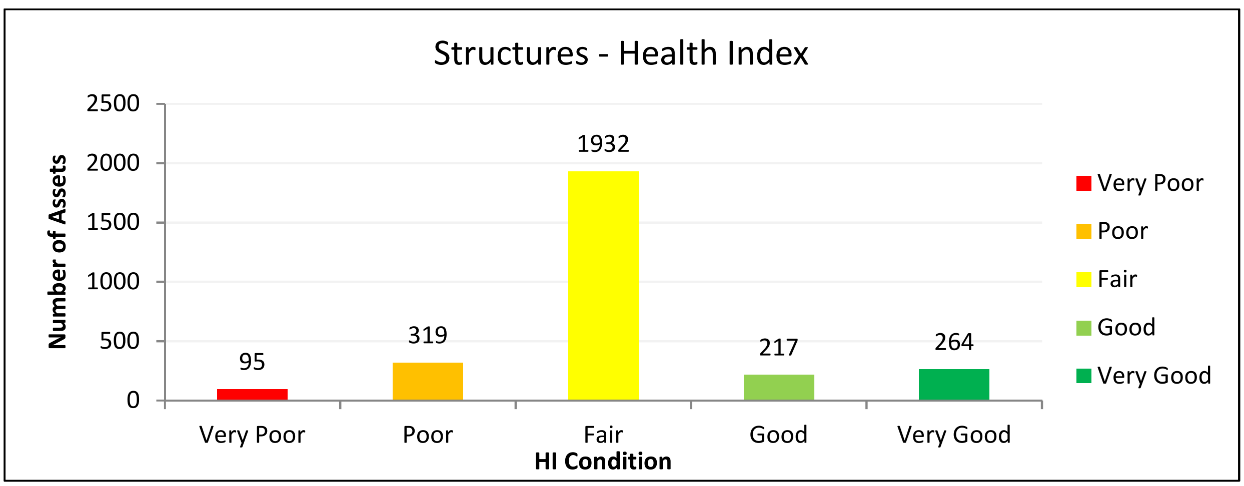
The health index score for a structure is composed of six separate condition parameters. The pole/structure condition is constructed by combining all sub condition parameters that describe the condition of the main structural components of the asset. In the case of steel and lattice structures, this includes bolt condition and corrosion levels. For composite structures, the pole/structure condition captures cracks, holes, or bending. In the case of a structures composed of wood poles, this includes insect infestation, wood pecker damage, shell rot, top rot, radial cracks, and remaining strength. When data is provided for every pole in a structure, the worst performing pole is used to describe the entire structure. This is because replacement decisions are made regarding entire structures and not individual components. It is more economically efficient to replace an entire structure than to replace only a single pole in a structure. Cross arm condition, insulator condition, guying condition, and grounding are included as condition parameters for structures with slightly decreased weights as they are less descriptive of the operational functionality of the structure when compared to the pole/structure condition parameter.

Figure 6.54: Data availability for Structure condition parameters

Condition Parameter	% of Assets with Data
Cross Arm Condition	91%
Pole/Structure Condition	100%
Insulator Condition	99%
Grounding	72%
Guy Condition	34%
Guy Anchor	35%

The average data availability across structures is 72%, in large part due to the missing assessments on structure grounding and guying condition. In general, detailed scoring was supplied for cross arm condition, pole/structure condition, and insulator condition across the structure population.

Figure 6.55: Health Index distribution for Structures asset class



There are 2,827 measured structures analyzed in the HOSSM system. Of the total structures analyzed, 264 are in Very Good, 217 in Good, 1932 in Fair, 319 in Poor, and 95 in Very Poor condition. By composition, 2524 of the total structures in the system are made of wood poles with an average health index of 53%. Composite poles are included in the group of 159 new structures installed via the Wood Pole Replacement Program, with every structure receiving a Very Good condition rating. There are 144 steel and lattice (tower) structures, with an average health index of 87%, which corresponds to a Very Good condition rating.

6.1.13.1 Structures – Wood

Figure 6.56: Sub-condition parameters for Wood Poles

Degradation Factor	Weight	Ranking	Numerical Grade	Max Grade
Age	15	A,B,C,D,E	4,3,2,1,0	60
Cross arm Condition	1	A,C,E	4,2,0	4
Insect Infestation	1	A,C	4,2	4
Pole Top Condition	1	A,C,E	4,2,0	4
Shell Condition	1	A,C,E	4,2,0	4
Wood Pecker Damage	1	A,C,E	4,2,0	4
Remaining Strength	20	A,B,C,D,E	4,3,2,1,0	80
Pole Treatment	5	A,C,E	4,2,0	20
Total Score				**180**

Wood structures constitute 83% of the total structures in the HOSSM system. A wood structure's Pole condition parameter is comprised of 8 degradation factors. Most significant is the age and remaining strength of the pole, with weights of 15 and 20, respectively. These are quantitative measurements that supply direct evidence of the deterioration of the operational health of the pole asset. Remaining strength is also a "gating" parameter. When the remaining strength for a pole is measured to be below 50%, the final health index for that pole is divided in half. This is because a lower remaining strength indicates significant degradation of the pole assets ability to perform its primary function. Additional degradation factors include cross arm condition, insect infestation, pole top condition, shell condition, wood pecker damage, and pole treatment condition.

There are single pole, 2-pole, 3-pole, and 4-pole structures in the HOSSM transmission system. The clear majority (81%) of these are multi-pole structures. For these structures, the worst performing pole's health score is taken as the overall Pole condition score for that structure. This is because replacement decisions are made regarding entire structures and not individual components as it is more economically efficient to replace an entire structure than to replace only a single pole in a structure. In the case where the deterioration of a single pole in a structure triggers an investment for replacement, it is highly likely that all the remaining poles in the structure would be replaced during the same period as well.

Figure 6.57: Health Index distribution for Wood subclass of Structures asset class

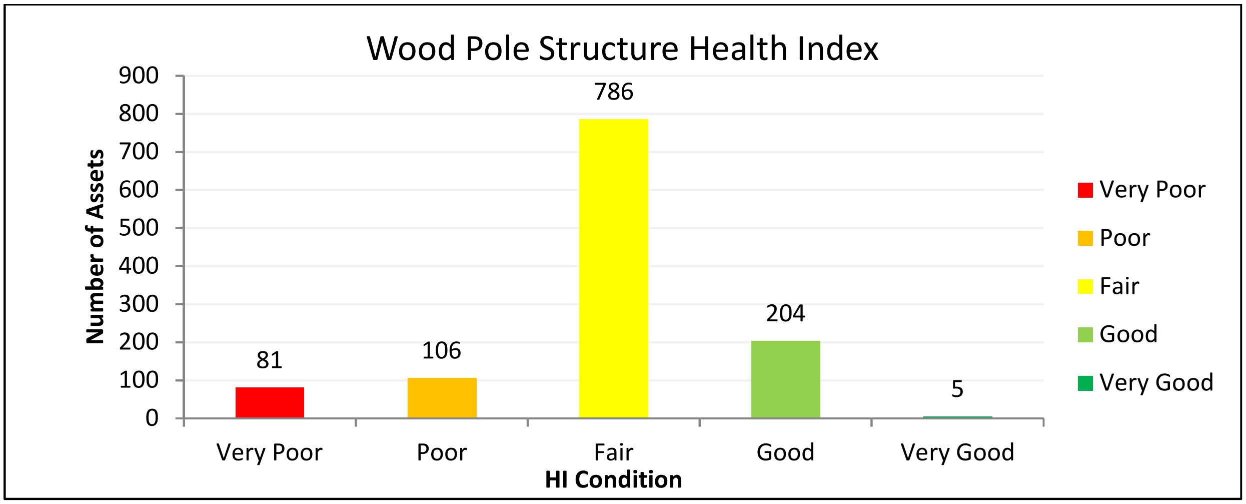
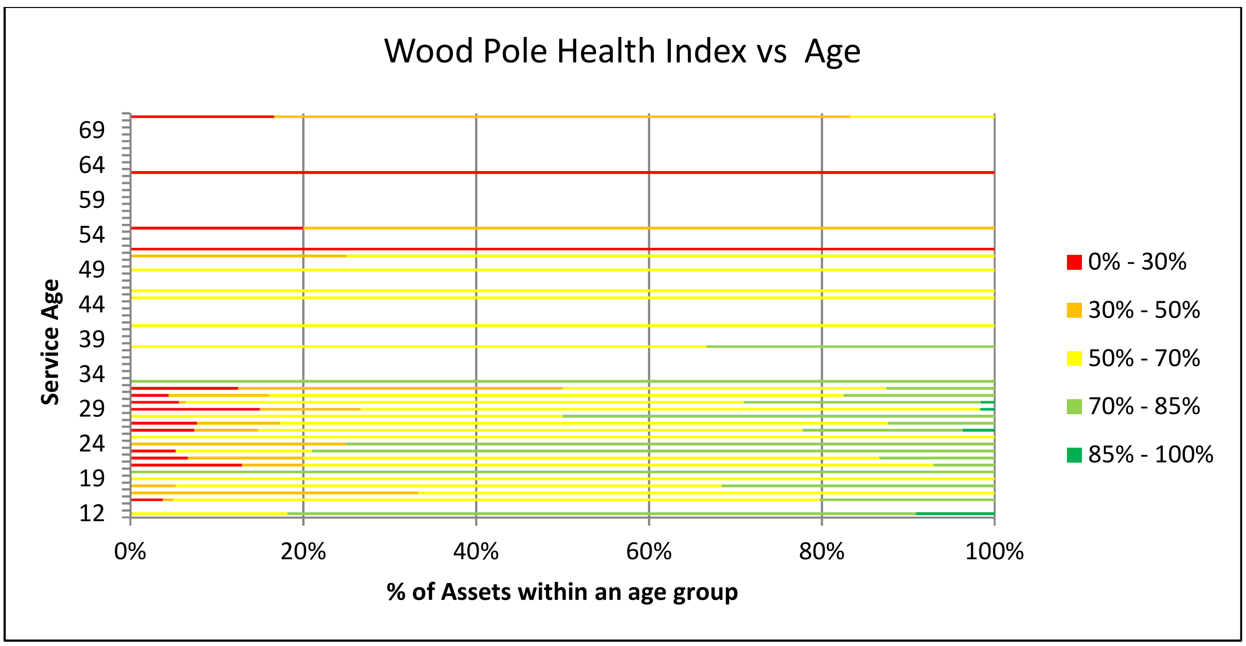


Figure 6.58: Health Index distribution of Wood Pole structures by Age



Most of the wood pole structures received a Fair condition score. There is however, a significant portion of the wood pole structures that are in Poor and Very Poor condition. From the age distribution, most of the more deteriorated structures have older installation dates. It should also be noted that there are some Poor and Very Poor condition wood structures scattered amongst the younger structure population as well. This is likely due to advanced woodpecker damage, or significant rotting of poles that are in wet areas. These are location dependent issues pertinent to these specific assets that were brought to attention by the HOSSM staff. It is believed that the Wood Pole Replacement program makes significant strides in addressing these issues across the population and will slowly improve the wood structure asset class health scores as the program continues to operate.

Figure 6.59: Heavy Woodpecker damage – holes filled with epoxy resin.

6.3. Data Availability and Data Gaps

When evaluating the maintenance reports for the five circuit switchers in the HOSSM system, there was no information indicating either the manufacture or install age of these assets. The circuit switchers in the system are providing a function analogous to that of a circuit breaker. For example, there are two parallel circuit switchers in both the Batchawana and Goulais transmission stations that serve as a method for removing the respective radial stations from the No. 3 Sault 115 kV transmission line. Across all of circuit breaker assets, age was the most critical condition parameter for calculating the health index of those units and carried the heaviest weight (30). This would also be the case for circuit switchers if age data was available, and a more accurate and detailed health index would be achievable in the presence of this data.

The Switches asset class also lacked a significant portion of manufacture or install-date data. It was therefore impractical to calculate any age-related condition scores for these assets. Currently all the switches evaluated in the HOSSM system are receiving a Very Good condition score. This is contrary to an expected distribution where some of the switches would be older, more worn, and therefore more severely degraded and receiving a lower condition score. It is believed that the inclusion of an appropriately weighted age condition parameter to the switch asset class would provide additional context and detail to their health indices, however this is only possible with a much greater data availability for Switch ages.

Although infrared thermography results were provided for the entire systems station assets, the level of detail in these scans was low. Opposed to reporting asset-level in-service temperatures, each asset in a transmission station simply received a checkmark.

This removed the ability to create an appropriately graded score for the thermal operation of each asset, and instead resulted in a binary scale where every asset evaluated received full marks. It is recommended that further and more detailed asset-level infrared thermography scans be conducted across the HOSSM station to help create more comprehensive and instructive asset health index scores.

Testing data regarding relays was largely collected using the Manta 5000 testing tool (Doble Instruments). Only 36% of the assets for which a health index was calculated had this testing performed during their lifetimes. Furthermore, although 36% of the units underwent onsite testing, only 52% of the tested units (19% of the population) have an associated visual inspection performed. The health indices for the relay asset class are therefore comprised primarily of age and obsolescence data. Although age and obsolescence are primary drivers for determining the health index of a relay asset, more detailed and descriptive analysis can be performed when the testing and visual inspection condition parameters are supplied more completely across the asset population.

Structure data was compiled from two separate studies conducted four years apart. The first study investigated the health of each structure. The structures distribution for the data set in which structures are given high scores on various parameters (3 on the contractor's scale) removed a large amount of separation between the Fair, Good, and Very Good structures. However, their scale allowed us to see the Poor and Very Poor (2,1) structures with high granularity. The second study generated scores for each pole in a structure. When data is provided for every pole in a structure, the worst performing pole is used to describe the entire structure. This is because replacement decisions are made regarding entire structures and not individual components. It is more economically efficient to replace an entire structure than to replace only a single pole in a structure.

The methodology between these two studies varied drastically. It is observed that there is very little overlap between the metrics being tested and the scoring practices for these metrics between each study. This fact made it difficult to consolidate the condition assessments made by each individual contractor into a singular health index for each structure asset. Further complicating the process were replacements or removal of structures in the interim. Due to the nature of HOSSM's current Wood Replacement Program, the only way to detect if a wood structure has been replaced is if the most recent evaluation for the structure is for composite type pole material.

6.4. Assets Flagged for Follow-Up

This list includes the station units that METSCO's assessment flagged as being especially deteriorated within the overall population of a given asset class. METSCO suggests that HOSSM review the units in question, conducting additional testing, where warranted, and identify the appropriate intervention strategy (if any) in the near term for these units. We note that it was not practical to include the line structures into this list, given the total number of deteriorated units identified.

6.4.1. Batteries

Within the Third Line transmission station, vented battery bank TSTHLB230 has a health index of 50%, corresponding to a Poor asset condition. The lower score is due to the progressed age of the asset (13 years old) and the alarming failures that were noted during the last maintenance performed on the asset. Additionally, at Northern Avenue transmission station non-vented battery bank TSNORA also has a health index of 50%. The primary contributing factor to the degradation of the asset is the underperformance of cells 3 and 4, which were noted during the most recent testing of the 10-cell bank.

6.4.2. Oil Breakers

The entire class of Oil breakers has health indices that provide them with Fair condition scores (50-70%). This is due to the advanced age of these assets, the associated external rusting and corrosion of their exterior surfaces, and obsolescence of certain oil circuit breakers in the asset class. As the age of the fleet of oil breakers continues to advance, the deterioration of these units will become more pronounced. The overall effect of the oil breaker asset population will be the movement from a Fair condition score to a Poor condition score. At this point, immediate steps would need to be taken to mitigate the degradation of these assets, such as refurbishment or ideally replacement. It is recommended that proactive steps be taken to mitigate the need for costlier reactive corrections to these assets, such as replacement dollar allocation and integration into the long-term capital plan.

6.4.3. SF6 Breakers

Of the SF6 type circuit breakers in the HOSSM transmission system, Clergue CB 169, Steelton CB 205, and Anjigami CB 844 received the lowest health scores (66%, 67%, 69% respectively). These assets are between 25 and 29 years of age. These units received low to medium scores across condition parameters associated with external condition and age. These external conditions include insulator condition, tank corrosion, and operating mechanism condition. It should also be noted that all the SF6 breakers located in Magpie and Echo River transmission stations are significantly progressed in age (29 to 32 years). Although the health scores for these assets are currently providing a Good condition score, degradation will become more rapid as the assets continue to age.

6.4.4. Power Transformers

The Third Line transmission station has two 230/115 kV autotransformers, T1 and T2. Transformer T1 was replaced in 2007, however its sister unit T2 still remains in service at the station. The T2 asset is currently 50 years old (manufactured in 1968) and has a health index of 51% which corresponds to a Fair condition, nearing on a Poor condition. The asset has heavy main tank corrosion and shows signs of oil leakage within the recent past. When METSCO visually inspected the transformer, there was evidence of pooling of small puddles of oil underneath the asset. The tap changer and main tank dissolved gas analysis results are Poor, and the oil quality for the asset is also Poor. Based on the asset's progressed age and declining health, it is suggested that the transformer be replaced within the next ten years to avoid potential failure of the asset. It is likely that the asset will be in Poor to Very Poor condition after this time, after which the risk of failure becomes large.

Figure 6.60: 230/115 kV Autotransformer T2 at Third Line Transmission Station

Goulais transmission station houses three transformers operating in a banked three phase configuration. Transformer T1-5027 was manufactured in 1980 and has a health index of 57%, T1-3717 was manufactured in 1976 and has a health index of 67%, and T1-

3129 was manufactured in 1973 and has a health index of 67%. These condition scores all correlate to a Fair condition. The assets have elevated moisture content, poor dissolved gas analysis results, and poor oil quality.

Figure 6.61: Banked Transformers at Goulais Transmission Station

Clergue transmission station has two transformers. Both transformers were manufactured in 1981 and are therefore 37 years old. Transformer MT1 has a health index of 61% and transformer MT2 has a health index of 54%. Both indices correspond to a Fair condition rating. The assets exhibit elevated moisture content, poor dissolved gas analysis results, and are under repetitive heavy loading during the winter seasons. It was noted during visual inspection from METSCO that the transformer MT2 was leaking in real time from the it's bushing gaskets, and transformer MT1 has significant pooling of oil in its containment pad. Due to the major contributor of moisture ingress and oil leakage to the degradation of these assets, it is suggested that the gaskets and seals for these units are replaced along with the oil. If this work is not performed, the assets will continue to degrade and may need replacement.

Figure 6.62: **Transformer MT2 at Clergue Transmission Station**

Echo River transmission station contains the in-service transformer T1, which was manufactured in 1986 (32 years old). The transformer currently receives 230 kV on its primary side and provides 34.5 kV from its tertiary to local distribution feeders. The 115-kV secondary is not in use. The asset received a health index of 56% which corresponds to a Fair condition score. The transformer received poor results for its dissolved gas analysis test, and the oil quality for the associated tap changer is also rated poor. Additionally, there is minor corrosion and oil leaks associated with the unit. Based on its lower health index, this asset should be integrated into a repair or replacement project within the next ten years to the mitigate system reliability risk associated with its degradation.

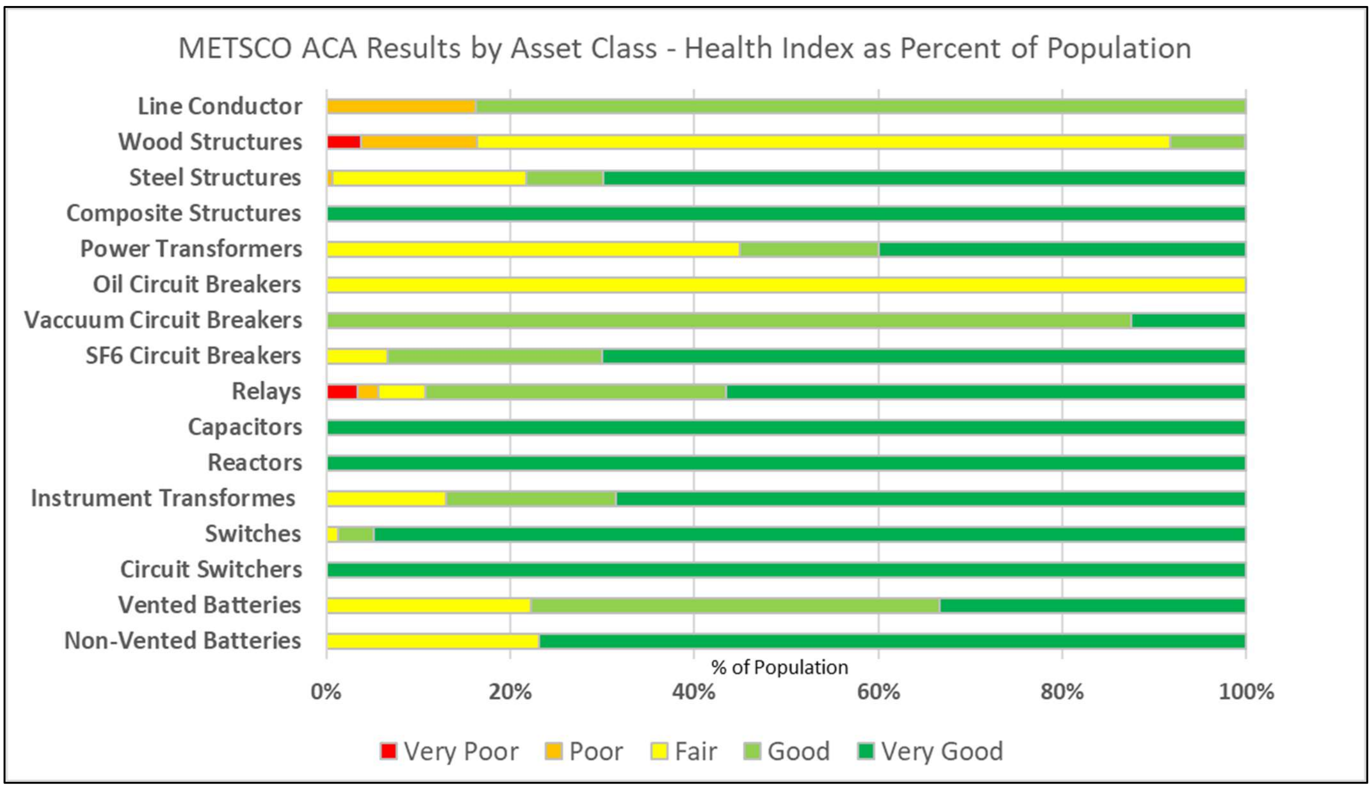
7. Overall Conclusions

7.1. Summary of Findings on Asset Health

7.1.1. Condition Results by Asset Class

As the Figure 7.1 indicates, the vast majority of HOSSM's assets across all asset classes analyzed is in Fair condition or better, with a significant portion of asset populations in Good or Very Good condition. This finding is also supported by the fact that equipment malfunctions have not been a systematic driver of outages, with the notable exception of conductor performance on the No. 3 Sault circuit, where HOSSM has taken steps to obtain empirical data on conductor performance and is reportedly planning to undertake the replacement of conductor and structures on the line in the coming years.

Figure 7.1: Asset Condition Findings by Asset Class



On balance, our findings indicate that HOSSM has taken prudent decisions in the past to sustain the health and performance of its system for the benefit of its customers and shareholders. As with every system, however, there are areas that require HOSSM's attention in the coming years where asset populations contain material portions of equipment in or approaching Poor condition or worse. Chief among these are transmission line wood support structures, the already noted conductor on the Number 3 Sault circuit, obsolete oil-based circuit breakers found to be in Fair condition, protection relays with units in Poor and Very Poor Condition, and several power transformer units that are currently in Fair condition but are approaching the boundaries of the Poor condition category.

In all cases where our analysis identifies particular units or population components for follow-up (as provided in detail in the asset-class specific sections of the preceding chapter), it is our recommendation that HOSSM performs follow-up analysis of these units' condition and performance before making specific decisions regarding the nature and timing of the ensuing intervention activities, such as additional testing, replacement, refurbishment or deferral.

7.1.2. Condition Results by Station and Line Criticality

As we discuss in Section 4.1.1, asset condition assessment results serve the utilities best when they employ the findings in preparation of a risk-based asset intervention plans. There are multiple examples of viable methodologies for conducting risk-based system planning, and we understand that HOSSM plans to use the results of this study in a risk-based planning framework that is currently in use at Hydro One.

While risk-based planning is not in the scope of METSCO's current engagement, we wish to assist HOSSM in its planning work by presenting our findings on the basis of a simple conceptual framework that ranks its system assets (grouped into individual stations and lines) according to their criticality to maintaining the overall system reliability and ensuring supply continuity for specific customers served by radial assets.

As we further elaborate in Section 4.1.1, our conceptual framework has separated all HOSSM lines and stations (along with equipment that they contain) into three broad criticality categories, with Level 1 assets being the most critical to maintaining the overall system reliability and operability, Level 2 assets responsible for supplying multiple downstream stations or large generation and load customers, and Level 3 assets being at once least critical for maintaining the overall system performance, and most critical for maintaining service continuity for HOSSM's downstream customers, many of which are supplied by assets that operate on a single contingency basis.

While our proposed ranking system ultimately prioritizes criticality to the ongoing system operation, we trust that our proposed categorization will assist HOSSM in balancing the considerations of system-wide reliability and customer service. Among other applications, for instance, we encourage HOSSM to use the results of our findings for Level 3 assets in its ongoing Customer Engagement activities as a discussion aid to facilitate joint decision-making. The results of our criticality-based presentation of the ACA results are provided in the figures below.

Figure 7.2: Asset Health by Station (Prioritized by Criticality)

Station	Power Transformers	Circuit Breakers	Instrument Transformers	Batteries	Switches	Relays	Circuit Switchers	Capacitor Banks	Reactors	Station Average
Level 1 Stations										
Third Line	71%	96%	100%	72%	92%	89%	-	94%	100%	89%
Mackay	93%	93%	99%	75%	95%	84%	-	-	94%	90%
Anjigami	85%	-	-	-	99%	97%	-	-	-	93%
Level 2 Stations										
Clergue	58%	55%	60%	88%	96%	74%	-	-	-	72%
Gartshore	-	85%	-	75%	75%	85%	-	-	-	80%
Steelton	-	76%	-	75%	98%	82%	-	-	-	83%
Watson	85%	74%	88%	76%	99%	69%	-	-	-	82%
Magpie	-	-	-	100%	97%	87%	-	-	-	95%
Level 3 Stations										
Echo River	56%	62%	75%	100%	-	86%	100%	-	-	80%
Hollingsworth	85%	74%	83%	100%	93%	87%	-	-	-	87%
Northern Ave	73%	86%	85%	50%	99%	74%	-	-	-	78%
Batchawana	69%	-	-	-	-	-	93%	-	-	81%
Goulais	64%	-	-	-	-	-	95%	-	-	80%
Highway 101	-	-	-	88%	-	100%	-	-	-	94%
Andrews	91%	-	-	100%	-	85%	-	-	-	92%

Figure 7.3: Asset Health by Circuit (Prioritized by Criticality)

Circuit	Average Structure HI	Average Conductor HI*	Circuit	Average Structure HI	Average Conductor HI*	Circuit	Average Structure HI	Average Conductor HI*
Level 1 Lines			**Level 2 Lines**			**Level 3 Lines**		
P21G	81%	Good	No 1 Garthshore	45%	Good	Andrews	57%	Good
P22G	50%		No 2 Garthshore	68%		Hogg	78%	
K24G	50%		No 1 Algoma	82%		No 3 Garthshore	78%	
W23K	50%		No 2 Algoma	76%		No 1 MacKay	44%	
No 3 Sault	55%	Poor	No 3 Algoma	80%		No 2 MacKay	41%	
			No 1 High Falls	50%		Northern Avenue	78%	
			No 2 High Falls	55%		Steephill	61%	
			No 1 Clergue	99%		Harris	63%	
			No 2 Clergue	100%		Mission Falls	65%	
			Magpie	56%		Hollingsworth	100%	
						Leigh's Bay	88%	
						Limer	49%	
						Anjigami	45%	

We note that in estimating the average replacement costs, we used publicly available information on the costs of equipment/materials only and did not factor in the capitalized labor or overhead costs that typically make up over 50% of an asset's replacement cost. Moreover, the equipment / materials replacement unit costs we used for this exercise do not specifically relate to HOSSM and should not be viewed as an indication of the expected costs. Our only intent in employing unit costs was to provide an objectively derived weighing factor for calculation of average condition of assets within each station, which would appropriately account for the order of magnitude differences in the costs of replacing larger assets (such as power transformers) and smaller equipment (such as batteries).

The majority of HOSSM's assets found to be in deteriorating condition correspond to the Level 3 assets, with several notable exceptions such as the previously noted No. 3 Sault circuit, which is one of the five lines identified in the Level 1 category and the Clergue Transformer Station characterized as a Level 2 station, where the condition of transformers and breakers suggests the need for follow-up analysis by HOSSM. It is METSCO's hope that this presentation of the ACA results provides HOSSM with a useful perspective on the condition of their assets in their upcoming risk-based system planning work.

7.1.3. Condition Results for the Overall System

As the final "segmentation" mode of presenting our asset condition assessment findings, we used the dollar-weighted average asset condition methodology to derive average Health Index for HOSSM's entire system, along with its two major components – namely the Lines and Stations subsystems. Figure 7.4 presents the results of this analysis.

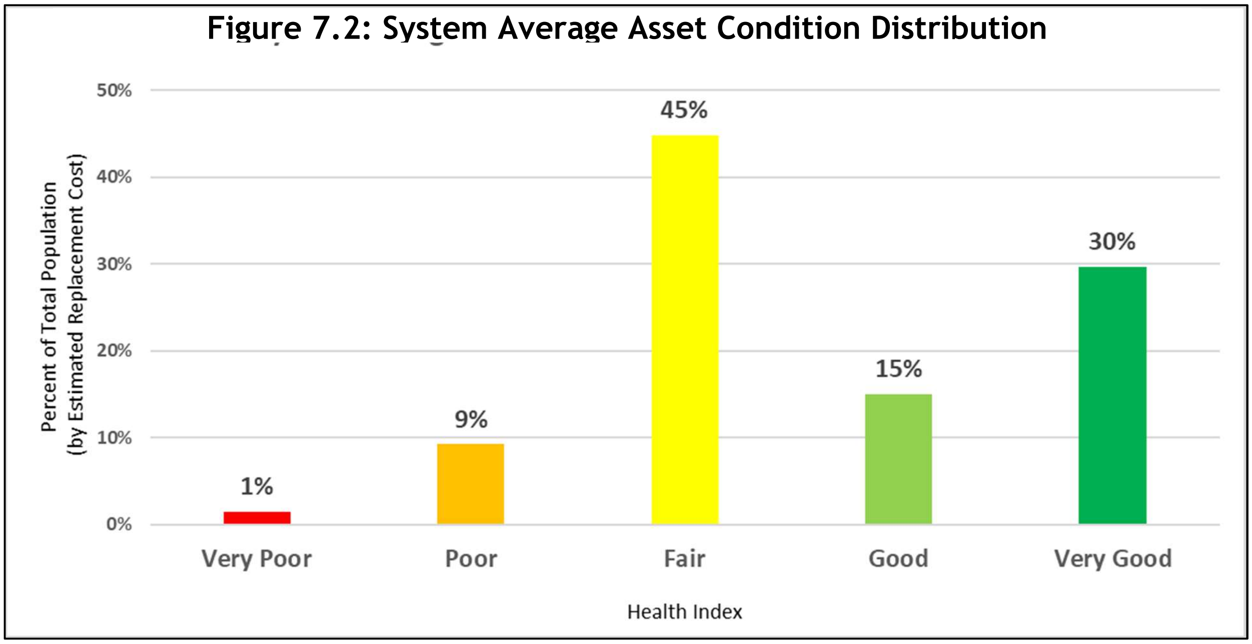
Figure 7.4 Average Dollar-Weighted HOSSM System Health Index

System / Subsystem	Average Grade	Condition
Lines	63%	Fair
Stations	82%	Good
Overall System	72%	Good

METSCO calculated the HOSSM system's overall Health Index using the weighted average approach described above to be 72%, which aligns with the Good condition rating, although one that is approaching the Fair territory (which starts at Health Indices of 69% and below). The calculated rating is largely due to the Fair rating (63% average HI) we calculated for the HOSSM's Lines subsystem, which offsets the Good (82% average HI) condition rating calculated for the Stations subsystem when deriving the system-wide average condition score.

For another perspective on system-wide average condition scores, Figure 7.5 breaks down the entire HOSSM plant across the five condition categories on the basis of average replacement costs of equipment determined to be in each category on the basis of our Health Index evaluation for each asset class. In providing this perspective on system-wide Health Index results for HOSSM's consideration, we reiterate our caution that the unit cost estimates used in this calculation include equipment/material cots only, that METSCO gathered from publicly available sources to provide an objective parameter on which to base the calculation of weighted averages.

Figure 7.5 HOSSM System Condition Distribution (by Estimated Replacement



The implications from the above presentation of results of our asset condition assessment confirm the need for HOSSM to continue investing in replacement and refurbishment of its system to address the 10% of its asset base (by estimated replacement dollar value) that are currently in the Very Poor and Poor category, and enhance its risk-based planning framework to effectively manage the almost half of its asset base that is currently in Fair condition and will continue deteriorating over the coming years.

The key asset category driving this distribution are transmission line wood structures, which our analysis has shown to be deteriorating on a significantly faster basis than what is typically expected from this type of equipment. HOSSM is addressing this issue through replacement of wooden structures in deteriorated condition with composite fiberglass equivalents, which it expects to help address a number of environmental factors that contribute to accelerated degradation of wooden units. Power transformers are another major asset category that makes up the significant portion of assets in the Fair condition category. We expect HOSSM to enhance its capabilities in managing this critical asset class by benefitting from the experience of Hydro One asset managers in the course of ongoing integration.

More generally, METSCO believes that presenting the ACA results distribution by portion of estimated total system replacement costs provides a helpful dimension from the perspective of long-term planning by providing a high-level snapshot of the magnitude of the financial implications of asset intervention decisions upcoming in the future. To manage this upcoming bow wave of assets that are currently in the Fair condition, which is consistent with the experience of most Ontario utilities, HOSSM will have to make informed tradeoffs to manage its capital program within the constraints of regulatory funding mechanisms.

As our asset condition findings indicate across all modes of their presentation, HOSSM has been a prudent asset manager in the past. As the utility embarks on incorporating risk-based planning that uses condition information along with other types of data inputs, METSCO expects it to continue managing its assets in an effective way as it proceeds towards operational integration with Hydro One.

7.2. Concluding Observations

7.2.1. Incremental Inspection and Testing Practices

In light of HOSSM's ongoing integration into the operations of Hydro One, METSCO expects that HOSSM's current data collection practices will undergo extensive review in the process of the ongoing integration activities with Hydro One. From previous experience with assessing Hydro One's asset management approaches, METSCO is aware that Hydro One's transmission asset management program relies on an extensive number of quantitative and qualitative parameters to select the most critical targets for asset intervention and utilize intervention modes that seek to minimize the greatest amount of risk facing the utility, its employees and customers.

Since METSCO expects the full scope of Hydro One's asset management practices to apply to HOSSM assets over time (which includes Hydro One's extensive maintenance requirements), we encourage HOSSM to concentrate on the integration work and do not offer any incremental suggestions at this time.

7.2.2. Asset Record Management Practices

The most challenging of completing this Asset Condition Assessment from METSCO's perspective was the work to digitize, integrate and verify the integrity of HOSSM's existing asset condition data which was previously stored in multiple paper-based and electronic databases. As HOSSM continues integrating its operating practices with Hydro One, the utility expects all of its asset condition data to be incorporated into Hydro One's SAP database in the coming months. While doing so will address the issue with asset data collected to date, we encourage both HONI and Hydro One to consider prioritizing an initiative that would ensure that ongoing HOSSM inspection and testing data continues being entered into the SAP environment using a cost-effective and sustainable process. This may involve instituting the use of hand-held electronic devises or other technology-based solutions. Irrespective of the solution, we encourage the staff overseeing the integration to put the issue of data management practices on the critical path - to leverage the momentum gained through database consolidation and the completion of this study.

This concludes METSCO's report on the condition assessment we performed for Hydro One Sault Ste. Marie LP. We wish the utility's staff all the best as they continue their system planning work.

8. Appendix A: External Studies Referenced in the Report

In the body of this report METSCO referenced the following two studies prepared by outside consultants. We are not including the studies themselves due to their length, as it would result in a sizable appendix. The studies are:

1. Kinectrics - 2015 Conductor Examination and Test Results on No. 3 Sault Line Circuit

2. One Line Engineering – 2011 Replacement of Protection Relays Study

9. Appendix B: METSCO Expert Team Bios

Robert Otal

P. Eng. Director, Asset Management & Analytics

SUMMARY OF QUALIFICATIONS

Robert Otal is a Professional Engineer with over 10 years of experience working in the areas of asset management, risk management, strategic long-term and short-term investment planning and information technology solutions. Mr. Otal has extensive experience in the development of long-term investment plans and short-term investment projects, risk and reliability-driven engineering decision-support systems, business case development, failure curve calibration and failure mode development, financial modeling, and process automation solutions. Mr. Otal has spearheaded the development of reliability projection methodologies using statistical analysis and data consolidation and has been involved with the development and implementation of best-practice reliability projection modeling for utilities. He has led the development of distribution system plans to support justification of investments as part of electricity distribution rate filing applications. Mr. Otal also led the development and delivery of strategic engineering projects to optimize processes and improve justification and decision-making as part of asset management planning procedures.

As part of his role at Toronto Hydro, Mr. Otal has worked hands-on in developing and optimizing Toronto Hydro's Distribution System Plan, and in developing the underlying risk-driven decision-support systems that support this plan. He previously worked at Horizon Utilities where he assisted with the implementation of their Asset Management Plan and condition assessment system to evaluate the distribution system assets. Mr. Otal obtained his B.Eng. in Electrical Engineering from Ryerson University, and is also a registered Professional Engineer in Ontario. His areas of interest include risk based analysis and optimization of distribution systems. Robert takes an active role in the Engineering profession and is a member of IEEE.

CAREER HISTORY

Education	**Ryerson University, 2005**

- Bachelor of Engineering (B.Eng.), Electrical Engineering

Professional Associations	Licensed Professional Engineer, Ontario, Canada IEEE Power & Energy Society (PES)

2015 to Present **Director, Asset Management & Analytics, METSCO Energy Solutions Inc.**

- Managed the development and integration of Asset Management Risk-Based Frameworks for a series of utility organizations
- Performed extensive data optimization exercises to aid utilities in storing relevant and accurate asset data for use in Asset Management procedures
- Developed and derived failure probability and failure impact parameters as part of a risk framework development exercise
- Performed alignment between risk frameworks and asset management standards including PAS 55 and ISO 55000
- Provided regulatory support to utilities when developing long-term capital and distribution system plans

2014 to 2015 **Supervisor, Strategic Analytics, Toronto Hydro**

- Managed the development and completion of Toronto Hydro's 5-Year Distribution System Plan (DSP), including the development of the documents' architecture such that it aligns to all requirements as well as the development of optimized processes to coordinate the production of standardized evidence.
- Managed development of decision-support tools and processes used support Toronto Hydro's 2015-2019 Electricity Distribution Rates (EDR) application, including the derivation of 5-year capital investment forecasts.
- Management of risk and reliability-driven decision support systems used to proactively identify investment opportunities.
- Managing the development of business case evaluation (BCE) processes and systems used to produce quantified justification for capital investment programs and projects.
- Managing the development of AM planning process improvements in order to introduce efficiencies and productivity improvements, including the development of geospatially-driven planning solutions for investment planning presentment and analysis.
- Management of engagement & contribution programs, including training, internal and external stakeholder engagement sessions.

2008 to 2011 Supervisor, Systems, Risk & Reliability, Toronto Hydro

- Lead development of the business case evaluation (BCE) procedure, to allow for capital programs to be evaluated using quantitative metrics including net present value.
- Developed procedure for the execution and evaluation of distribution automation (DA) projects – procedure allowed for optimal placement of DA-enabled switches, such that future customer impacts could be substantially reduced, thereby maximizing benefit of projects
- Developed and calibrated age-based and condition-based failure probability curves and failure modes as part of enhancements to Feeder Investment Model (FIM)
- Management of system-level reliability planning processes, including tracking, reporting and forecasting.
- Management of risk management systems development and reporting processes.
- Managing the development of long-term capital plans, investment strategies and regulatory justification.
- Managing the development of systems and tools to aid in planning, decision-making and justification.

2008 to 2010 Risk & Analytics Engineering Lead, Toronto Hydro

- Led development of Engineering Intelligence (EI); a geospatially-driven planning solution that will allow planning engineers to identify worst-performing assets & locations, perform simulations & scenario analyses, create capital project scopes and produce qualitative and quantitative justification as part of a business case evaluation procedure.
- Led development of the Feeder Investment Model (FIM); a risk-based decision support tool utilized by planning engineers to identify and prioritize high-risk assets and to perform business case evaluations for capital project scope justification.
- Developed Quantified Risk Evaluation Framework for substation assets, including power transformers and switchgear assets. Existing substation and protection & control designs were incorporated and evaluated as part of this framework. Outputs included the identification of high-risk substation configurations and action plans to mitigate these risks.
- Lead development of Electrical Distribution Capital Plan (EDCP) - a ten-year capital plan which highlights challenges across the distribution system and includes key programs and initiatives to

mitigate system risks and improve reliability. EDCP represented a key regulatory document submitted as part of EDR filing.
- Produced capital project scopes to drive asset renewal activities and improve reliability. Scopes included design requirements, business case evaluation and justification.
- Developed long-term distribution plan and assessments for 4.16kV distribution system, including evaluation and analysis of aging rear-lot infrastructure, load transfer & contingency analysis, fuse coordination studies, loading and capacity calculations.
- Current-state manual processes and data gaps were assessed and prioritized as part of strategy aimed at developing new turn-key automation solutions in order to optimize asset management efficiencies. Plan identified key responsible parties and change management requirements.

2006 to 2008 **Engineer-in-Training, Horizon Utilities**

- Lead development of asset risk scoring framework, to prioritize assets based upon their probability & impact of asset failure.
- Lead development of asset condition assessment (ACA) program, to quantify asset health and prioritize assets.
- Developed Asset Management Plan, to document key programs and methodologies applied to maintain and renew asset infrastructure.
- Involved in regulatory filing processes, including the preparation of materials/justification to support planning programs and provide current state assessment of asset infrastructure.
- Developed designs and requirements for capital projects to renew existing asset infrastructure and support new customers.

Selected Technical Publications and Presentations

R. Otal and A. Bakulev, “Risk-Based Asset Management Optimization”, T&D Conference & Exposition, 2014 IEEE PES, pp. 1-5, Internet:

http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6863414&isnumber=6863147. 2014.

R. Otal and T. Hjartarson, “Sustainment Actions Take a New Direction”, Transmission & Distribution World Magazine, pp. 27-34, October 2010.

R.Otal and C. Kerr, "Toronto Hydro's Asset Management Planning & Evaluation Process", DistribuTECH 2014, Internet: http://s36.a2zinc.net/clients/pennwell/dtech2014/Public/SessionDetails.aspx?FromPage=&SessionID=6973. February 2014

R. Otal and A. Bakulev, "Risk-Driven Business Case Evaluation of Capital Projects", DistribuTECH 2013, Internet: http://s36.a2zinc.net/clients/pennwell/dtech2013/Public/SessionDetails.aspx?FromPage=Calendar.aspx%20&SessionID=3650, February 2013

Gokhan Saltan

B. Sc., P. Eng., PMP

SUMMARY OF QUALIFICATIONS

Gokhan Saltan is a professional engineer with nearly two decades of experience in planning, design, and execution of electricity transmission infrastructure across Canada. To date, Mr. Saltan held senior engineering and project management positions at a number of prominent electrical engineering consultancies, including Acres International, Hatch, and SNC Lavalin. During this time, he participated in and oversaw the development of a variety of technical products, including asset condition assessments, transmission station and line design projects, load flow studies, feasibility assessments, and construction project planning, among others. Prior to joining METSCO, Mr. Saltan oversaw engineering and design of transmission lines connecting the Lower Churchill Falls hydroelectric generation project in Newfoundland and Labrador. At METSCO, Mr. Saltan acts as the senior subject area expert in transmission system planning, design and operation, and oversees technical knowledge development of the company's junior associates. Mr. Saltan holds a Bachelor of Science degree in Electrical Engineering from the Middle East Technical University, in Ankara, Turkey, along with the Professional Engineer (P. Eng.) and Project Management Professional (PMP) designations.

CAREER HISTORY

Education	**Middle East Technical University, Ankara, Turkey** B. Sc, Electrical Engineering, 1996
Employment History	
April 2018 to Present	**Senior Associate, Transmission Planning, METSCO Energy Solutions.** Subject area lead expert on planning, design and operations management of transmission system assets.
March 2011 to February 2018	**Manager, Engineering, Transmission Lines - Lower Churchill Falls Project - SNC Lavalin**

Oversaw day-to-day operations of engineering and design teams supporting the construction of transmission infrastructure supporting the Lower Churchills Generating Project.

November 2009 to March 2011	**Manager, Substation and Transmission Lines - SNC Lavalin ATP** Led a team of engineering professionals on a number of planning and projects for greenfield assets and modifications to the existing systems across North America.
June 2005 - November 2009	**Senior Engineer - SNC Lavalin ATP** Participated in a variety of engineering projects supporting design and construction of transmission system assets in various jurisdictions.
2002 to 2005	**Senior Electrical Engineer - Acres International / Hatch.** Conducted a variety of technical studies and design projects for multiple utility clients across North America.

Dmitry Balashov

MBA, MPA. Director, Utility Strategy and Economic Regulation

SUMMARY OF QUALIFICATIONS

Dmitry Balashov is a utility strategy professional with a decade of experience spanning government policy development, utility regulation, and management consulting. Dmitry's areas of focus include utility regulation, strategy, and productivity and performance optimization of capital asset management, supply chain, and back office operations. Prior to joining METSCO, Dmitry held senior advisory positions at Toronto Hydro and the Ontario Ministry of Energy. Over the last decade, he has contributed his knowledge and passion to over 20 high-profile energy regulation proceedings in Ontario, Manitoba and Alberta. Most recently, Dmitry's focus has been on METSCO's growing Utility Strategy practice area, where he works with utility senior management to develop, and effectively integrate into existing operations, new performance measures, tools and processes designed to optimize operating performance and shareholder returns, while complying with regulatory guidance. Dmitry has recently graduated at the top of his class with an Executive MBA at University of Toronto's Rotman School of Management, where he concentrated on energy project finance, strategy and operating efficiency. While at Rotman, Dmitry was retained as an instructional advisor for an Electric Utility Productivity Capstone Course for the Full-Time MBA Students.

CAREER HISTORY

Education

University of British Columbia, Vancouver

- B.A. Political Science, 2005

Queen's University School of Policy Studies, Kingston

- MPA, Energy Policy, Trade Policy, 2008

Rotman School of Management, Toronto

- MBA, Strategy and Operations Management, 2018

May 2017 to Present — **Director, Utility Strategy and Economic Regulation, METSCO Energy Solutions Inc.**

Providing expert advisory services to select utility and government clients in the areas of economic regulation, asset management, benchmarking and utility sector productivity.

- Led preparation of a framework of capital asset performance measures for a mid-sized Ontario utility;
- Acted as a third-party expert in the area of asset management during a major regulatory hearing;
- Developing numerous reports and research studies in the areas of reliability forecasting, capital asset management and analytics.

March 2015 to May 2017 **Lead, Regulatory Process and Analytics, Toronto Hydro**

- Led a team of legal, finance and policy professionals in preparation and prosecution of applications for regulated tariffs for the largest municipal electric utility in Canada.
- Facilitated the development and implementation of compliance programs in the areas of customer care, operations management and investment coordination and planning.
- Oversaw the research and development of policy advocacy submissions to the Ontario Energy Board (OEB) in areas of customer care, cost of capital, and reliability.
- Collaborated with internal subject matter experts on development and implementation of business planning process enhancements and productivity programs.
- Supported senior leadership in preparation and delivery of strategic planning and advocacy documents, including executive and Board of Directors briefings.

May 2013 to March 2016 **Regulatory Affairs Consultant, Toronto Hydro**

Led research, analysis, planning and drafting of performance measurement, productivity and OM&A evidence for Toronto Hydro's 2015-2019 tariffs application.

- Conducted inter-jurisdictional research and proposed frameworks for CIR ratemaking model and productivity evidence presentation;
- Coordinated preparation, research and drafting of Interrogatory and Undertaking responses on the subjects of productivity, OM&A and performance measurement;
- Coordinated work of four expert working groups tasked with development of complex and strategically significant evidence (Productivity, KPIs, ERP, Operations Support);
- Liaised with Provincial Government officials and OEB staff on a range of ongoing policy consultations, mutual undertakings and logistical matters.

2011 to 2013 **Senior Policy Advisor, Regulatory Affairs and Strategic Policy, Ontario Ministry of Energy.**

- Led the Government's analysis of Hydro One's ratemaking strategies, capital investment plans and business planning assumptions. Conducted financial analysis of the impact on the Province's fiscal plan of policies and programs contemplated by Hydro One and Ontario Power Generation.
- Contributed to planning and governance policy development and drafting of the Ontario Electricity System Operator Act, 2012;
- Led options development and advised senior officials on potential changes to content and appearance of consumer electricity bills, and transition to fixed distribution billing;
- Provided strategic analysis of key stakeholder submissions to the Ontario Distribution Sector Review Panel;
- Regularly liaised with Hydro One staff and Executive Officers to provide the Ministry's feedback on key regulatory and financial issues.

2008 to 2011 **Policy Analyst, Transmission and Distribution Policy, Ontario Ministry of Energy.**

- Researched and drafted policy papers, briefing materials, and cabinet submissions on a variety of topics, including network upgrade planning and grid investment incentives.
- Led and supported government consultation activities with the First Nations and Metis communities affected by contemplated energy infrastructure projects;
- Prepared communications documents for senior civil service and political staff to communicate complex concepts in simple and effective manner;
- Conducted analysis of customer rate impacts of anticipated regulatory decisions by the OEB and procurement programs by the Ontario Power Authority (OPA);
- Advised stakeholders on technical issues and legislative/regulatory tools that govern development and approvals of transmission projects;
- Participated in drafting of the Green Energy Act, 2009 and the development of the Ontario Feed-In Tariff grid connection rules.

Kinectrics Test Report
Appendix C

SRD

Sault #3 Outage Summary and General Notes

Recent Outage History:

1) 2013 – Str 268 – Sleeve failure in Chippewa area
2) 2014 – Str 495 – Sleeve failure in Shoepack Lake area
3) 2015 Feburary – Str 134-135 – Sleeve failure over Highway 17 south of post office road. This is south of Goulais TS
4) 2015 November – Str 171.5 – Tree on line
5) 2016 December – Str 170 – Tree burning line in Stokley area

Notes:

Goulais to Batch are structures 136 to 231

New conductor was installed on Sault #3 from Str 1 to 129.

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 266.8 kcmil 26/7

TEST DATE : June 15, 2015 | TESTED by : Pras P. and Mike Colbert | KINECTRICS REF. NO. : 419717 - GLP - 2015 - 01

KINECTRICS

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY or GPS	RECEIVED DATE
na	na	na	na	01-Apr-15

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR | Designation : 266.8 kcmil 26/7 | Nom. Cable Diameter ** : 0.642 in | Measured Cable Diameter : 0.643 in

	Alum. Outer Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Min. Breaking Strength	26,000 psi	Min. Breaking Strength	210,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1013 in	for a single wire = 197 lbf	0.1013 in	for a single wire = 197 lbf	0.0788 in	Min. Breaking Strength of single wire = 1,024 lbf
Area of Wire :	0.00806 sq. in		0.00806 sq. in		0.0049 sq. in	Min. Load @ 1% Elongation = 927 lbf
Number of Wires in Layer :	16		10		7	For Tension Test Load @ 1% Elongation **** :
Number of Wires Tested :	4		4		7	Preload = 71.05 lbf., Offset = 0.005 in.
Tension Load for Torsion Test * :	1.97 lbf	= 0.896 kgf	1.97 lbf	= 0.896 kgf	10.24 lbf	= 4.645 kgf
Torsion Test sample length * :	14.66 in	= (120 x dia. + 2.5")	14.66 in	= (120 x dia. + 2.5")	11.96 in	= (120 x dia. + 2.5")

TEST RESULTS

	Alum. Outer Layer			Alum. Inner Layer			Steel and Core Wires				
Measured Wire Diameter : (for identification only)	0.1010 in			0.1010 in			0.0785 in	(use core wire)			Remaining Zinc [3] % Zinc (avg of wires 1-6) vs. Core Wire
	The outer surface of the alum. wires had :			The outer surface of the alum. wires had :			The outer surface of the steel wires had :				
	Contam	Pitting	Color	Contam	Pitting	Color	Category [1]	Rating [2]	Rust	Pitting	
	light-moderate	very mild	grey/dark	light	none	dark	2c	2	very light	negligible	81%

Comments :

Alum. Outer Layer: The outer surface had fixed black contamination on one side. It rubbed off with brillo pad. There were very small pits. Also some wire had either manufacturing or installation grooves. The inner surface had mild fixed & loose dark contam & fret marks. At adjacent wires interface, there was sporatic moderate corrosion spots under the black contam.

Alum. Inner Layer: The outer surface had lots of loose dirt contam on and between wires. Fixed dark contam covered most areas.. Had fret marks. One side had a little more dark contam than the other. The inner surface had moderate corrosion products at about 8" spacing. Underneath, the surface was moderately corroded. There were fret marks too.

Steel and Core Wires: The outer surface was mostly covered in brown and white contamination, indicating corrosion. Zinc was corroded. After removing zinc coating, very light corrosion was observed, and signs of pitting commencing. The inner surface had some fixed contam. No corrosion observed after removing zinc. The core wire had some fixed contam. Found small spots of very light corrosion after removing zinc.

WIRE No.	Outer: Number of Turns	Outer: Breaking Strength lbf	Outer: Breaking Strength psi (calc)	Inner: Number of Turns	Inner: Breaking Strength lbf	Inner: Breaking Strength psi (calc)	Steel: Number of Turns	Steel: Load @ 1% Elongation, lbf	Steel: Breaking Strength lbf	Steel: Breaking Strength psi (calc)
1	50.2	177	21,962	50.0	169	20,969	21.3	813	890	182,494
2	56.9	168	20,845	45.8	180	22,334	21.5	895	1011	207,305
3	53.3	182	22,582	32.2	188	23,326	17.7	868	973	199,513
4	50.6	170	21,093	47.8	188	23,326	21.5	894	1009	206,894
	50.9	177	21,962	46.9	173	21,465	20.9	895	1018	208,740
6	51.9	170	21,093	56.8	171	21,217	30.6	838	940	192,746
7 (core wire)	-	-	-	-	-	-	28.4	864	996	204,229
Average (Steel & Core 'No. of Turns' is Avg. 1 to 6) :	52.3	174	21,589	46.6	178	22,106	22.3	867	977	200,274
Avg.Strength x # of Wires in Layer :	(A)	2,784 lbf		(B)	1,782 lbf					
Measured Strength (Alum/Steel) :		A+B=(C)	4,566 lbf					(D)	6,837 lbf	
Calculated Total Strength of Layer :	(E)	3,353 lbf		(F)	2,095 lbf			(G)	7,169 lbf	
Measured / Calculated (%) :	A/E =	83.0%		B/F =	85.0%			D/G =	95.4%	
Total Load on Steel @ 1% Elongation :							(H)	6,067 lbf	= 93.5% of Nom 1% Load	
Total Measured Breaking Strength :			C+H=(J)	10,633 lbf	=	94.6%	of Book Value.			
Derated Meas. Breaking Strength ***** :			(K)	10,070 lbf	=	89.6%	of Book Value.			
Rated Breaking Strength ** (book value) :			(L)	11,240 lbf						

- Shaded areas indicate data manually entered or calculated. (Data & Photos Stored in :I:\TDT\LAM 419)

See Page 2 for Test Methods and Specifications. See Page 2 for asterisk (*) and footnote explanations. Page 1 of 10 Revision 2014-15

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 266.8 kcmil 26/7

KINECTRICS

TEST DATE : June 15, 2015 **TESTED by :** Pras P. and Mike Colbert **KINECTRICS REF. NO. :** 419717 - GLP - 2015 - 01

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY or GPS	RECEIVED DATE
na	na	na	na	01-Apr-15

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 266.8 kcmil 26/7 Nom. Cable Diameter ** : 0.642 in

	Alum. Outer Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Min. Breaking Strength for a single wire = 197 lbf	26,000 psi	Min. Breaking Strength for a single wire = 197 lbf	210,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1013 in		0.1013 in		0.0788 in	Min. Breaking Strength of single wire = 1,024 lbf
Area of Wire :	0.0081 sq. in		0.0081 sq. in		0.0049 sq. in	Min. Load @ 1% Elongation = 927 lbf
Number of Wires in Layer :	16		10		7	For Tension Test Load @ 1% Elongation **** : Preload = 71.05 lbf., Offset = 0.005 in.
Number of Wires Tested :	4		4		7	
Minimum Elongation in 10", at Failure, in Percent (%) : ***	1.5 %		1.5 %		3.0 %	

TEST RESULTS

WIRE No.	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %
1	0.82	0.72	4.84
2	1.18	0.84	5.30
3	0.91	0.66	4.66
4	0.92	0.79	4.93
5	0.88	0.66	5.43
6	0.90	0.77	4.69
7 (core wire)			6.65
Average :	**0.94**	**0.74**	**4.98** (1 to 6)

- Shaded areas indicate data manually entered or calculated.

Tension & Elongation Test Method : ASTM B557-02a for Aluminum wires & ASTM A370-09a for Steel wires.
* Torsion Test Method : ASTM A938-04 (Using 1% of Nominal Breaking Strength of wire for Tension load).
** Wire & Cable Diameters and Rated Breaking Strength taken from Ontario Hydro ACSR Conductor data catalogue.
*** Values for Aluminum wires from ASTM B230-07 Table 1, and for Steel wires from ASTM B498-08 Table 2.
**** Values for 1% Elongation from CSA CAN3-C49.6-M85, Table 2.
***** Derating values from Southwire Overhead Conductor Manual, Table 1-14.

[1] 'Category' from Table 2, Page 3.
[2] 'Rating' from Table 3, Page 3
[3] 'Remaining Zinc' from Table 1 (H), Page 3

Revision 2014-15

MEMORANDUM

KINECTRICS

Date	August 11, 2015
Attention	Mr. Matt Baker
Company	Great Lakes Power (GLP)
From	Dmitry Ladin, Paul Fong
Subject	Implosive Connector Dissection
Memo #	K-419717-0001-TM-0001-R00

Great Lakes Power (GLP) requested to investigate a failed connector and three (3) non-failed connectors removed from the same circuit, in order to review the connector condition. The connectors are of implosive type, and specifically from Implo® brand (a Burndy Inc. brand name). All test samples were received at Kinectrics on March 10, 2015.

Mr. Matt Baker informed that the failure occurred at cold ambient conditions (-35 deg. C) during winter 2015 at Sault #3 115 kV Circuit, just outside Goulais TS. The conductor is 266.8 (26/7) ACSR (Note: conductor condition was reviewed separately and reported to GLP).

All received connectors have been mechanically dissected to reveal inner connector and conductor condition. See details below.

Prepared by:

Dmitry Ladin

D. Ladin
Engineer/Scientist
Transmission and Distribution Technologies Business

DISCLAIMER

Failed Connector Dissection

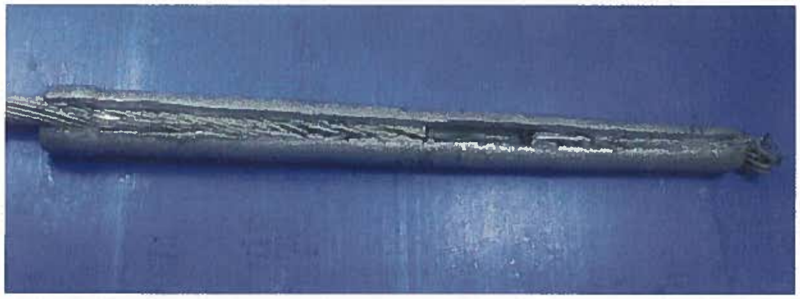


Figure 1: Failed Connector Dissected

Figure 2: Failed Connector End: note conductor strands melting

Figure 3: Failed Connector: opened to review inner condition

Figure 4: Failed Connector: non-failed side, clean contact areas, no corrosion

Figure 5: Failed Connector: solid stop in place

Figure 6: Failed Connector: dislodged conductor on failed side

Figure 7: Failed Connector: imprints on connector sleeve point to proper conductor insertion during installation and conductor partial withdrawal during overheating and failure

Figure 8: Failed Connector: failed conductor end, no signs of corrosion

Non-Failed Connector: Phase C

Figure 9: Connector Dissected

Figure 10: Dissected Connector: opened to review inner condition

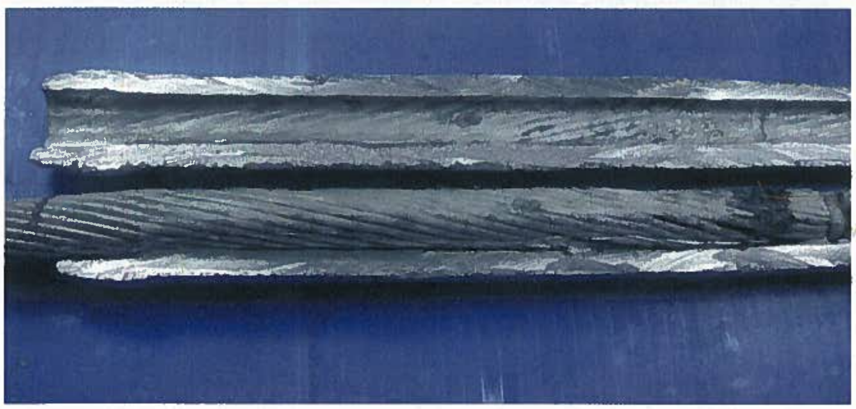


Figure 11: Dissected Connector: proper conductor positioning, no corrosion

Figure 12: Dissected Connector: note electrical tape left on conductor during installation – reduced electrical contact inside connector

Figure 13: Dissected Connector: conductor is clean, no corrosion, no visible contamination

Non-Failed Connector: Phase B (Connector #1)

Figure 14: Connector Dissected

Figure 15: Connector Dissected: note manufacturer's P/N, date code (same P/N on all reviewed connectors)

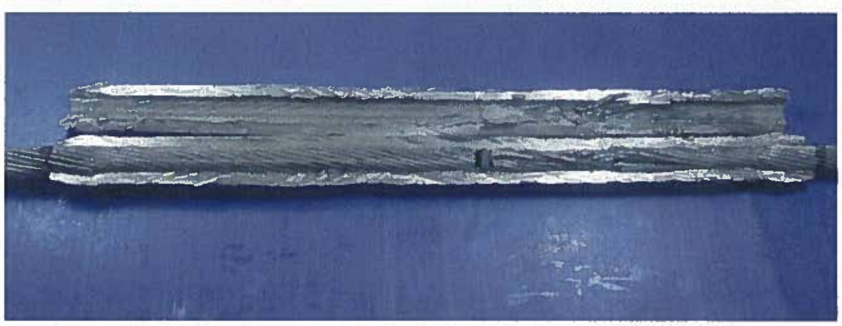


Figure 16: Dissected Connector: opened to review inner condition

Figure 17: Dissected Connector: proper conductor location, no signs of corrosion

Figure 18: Dissected Connector: solid stop located, conductor on both sides properly positioned

Figure 19: Dissected Connector: possible conductor damage (one area) due to overheating or due to prep work during installation

Non-Failed Connector: Phase B (Connector #2)

Figure 20: Dissected Connector: opened to review inner condition; note some strands moved during dissection

Figure 21: Dissected Connector: clean contacts, no corrosion

Figure 22: Dissected Connector: conductor on right-hand side removed to show connector sleeve; note black residue on the conductor surface in this area

Figure 23: Dissected Connector: note onset of corrosion on conductor strands (right-hand)

THIS COND. IS NEAR E.O.L.

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 266.8 kcmil 26/7

TEST DATE : Dec 8-11, 2014 **TESTED by :** Geoffrey A / Mike C **KINECTRICS REF. NO. :** 419649 - GLP - 2014 - 02

KINECTRICS

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY or GPS	RECEIVED DATE
na	No. 3 Sault 155kV Line	495 - 496	Long Section connected to Splice	31-Oct-14

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 266.8 kcmil 26/7 Nom. Cable Diameter ** : 0.642 in Measured Cable Diameter : not available

	Alum. Outer Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Min. Breaking Strength	26,000 psi	Min. Breaking Strength	210,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1013 in	for a single wire = 197 lbf	0.1013 in	for a single wire = 197 lbf	0.0788 in	Min. Breaking Strength of single wire = 1,024 lbf
Area of Wire :	0.0081 sq. in		0.0081 sq. in		0.0049 sq. in	Min. Load @ 1% Elongation = 927 lbf
Number of Wires in Layer :	16		10		7	For Tension Test Load @ 1% Elongation **** :
Number of Wires Tested :	4		4		7	Preload = 71.05 lbf., Offset = 0.005 in.
Tension Load for Torsion Test * :	1.97 lbf	= 0.896 kgf	1.97 lbf	= 0.896 kgf	10.24 lbf	= 4.645 kgf
Torsion Test sample length * :	14.66 in	= (120 x dia. + 2.5")	14.66 in	= (120 x dia. + 2.5")	11.96 in	= (120 x dia. + 2.5")

TEST RESULTS

Measured Wire Diameter : → (for identification only)	0.1000 in			0.1010 in			0.0800 in (use core wire)				Remaining Zinc [3] % Zinc (avg of wires 1-6) vs. Core Wire
	The outer surface of the alum. wires had :			The outer surface of the alum. wires had :			The outer surface of the steel wires had :				
	Contam	Pitting	Color	Contam	Pitting	Color	Category [1]	Rating [2]	Rust	Pitting	
	light	none	grey/dark	light	none	dark	2b	2	very light	none	81%

Comments :

Alum. Outer Layer: The outer surface had fixed black contamination on one side. It rubbed off with brillo pad. Underneath the surface was okay. There were some small melted spots. The other side was grey & had discolored aluminum with many melted spots. The inner surface had mild fixed dark contam & fret marks. Rubbed off with brillo pad to a grey colored surface.

Alum. Inner Layer: The outer surface had loose dirt contam on and between wires. Wiped off easily. Had fret marks. One side had a little more dark contam than the other. The inner surface had loose & fixed dirt contam over the entire surface.

Steel and Core Wires: The outer surface was mostly covered in brown and white contamination, indicating corrosion. Zinc was corroded. After removing zinc coating, very light corrosion was observed. The inner surface was dark in color. Had some fixed contam. No corrosion observed after A90 test. The core wire was in dark color. Had some fixed contam. No corrosion observed after A90 test.

WIRE No.	Alum. Outer: Number of Turns	Alum. Outer: Breaking Strength lbf	Alum. Outer: Breaking Strength psi (calc)	Alum. Inner: Number of Turns	Alum. Inner: Breaking Strength lbf	Alum. Inner: Breaking Strength psi (calc)	Steel: Number of Turns	Steel: Load @ 1% Elongation, lbf	Steel: Breaking Strength lbf	Steel: Breaking Strength psi (calc)
1	39.4	166	20,597	70.8	164	20,349	36.8	873	932	191,106
2	53.6	166	20,597	55.4	171	21,217	39.9	938	1026	210,380
3	29.2	180	22,334	44.5	178	22,086	41.2	925	959	196,642
4	84.8	180	22,334	44.0	152	18,860	38.2	902	989	202,793
	69.5	172	21,341	45.7	156	19,356	42.5	854	922	189,055
6	26.0	149	18,487	41.9	142	17,619	41.7	907	984	201,768
7 (core wire)	-	-	-	-	-	-	41.6	885	933	191,311
Average (Steel & Core 'No. of Turns' is Avg. 1 to 6) :	**50.4**	**169**	**20,948**	**50.4**	**161**	**19,914**	**40.1**	**898**	**964**	**197,579**
Avg.Strength x # of Wires in Layer :	(A)	**2,701 lbf**		(B)	**1,605 lbf**					
Measured Strength (Alum/Steel) :		A+B=(C)	**4,306 lbf**					(D)	**6,745 lbf**	
Calculated Total Strength of Layer :	(E)	**3,353 lbf**		(F)	**2,095 lbf**			(G)	**7,169 lbf**	
Measured / Calculated (%) :	A/E =	**80.6%**		B/F =	**76.6%**			D/G =	**94.1%**	
Total Load on Steel @ 1% Elongation :							(H)	**6,284 lbf**	**= 96.9% of Nom 1% Load**	
Total Measured Breaking Strength :				C+H=(J)	**10,590 lbf**	=	**94.2%**	**of Book Value.**		
Derated Meas. Breaking Strength *****				(K)	**10,038 lbf**	=	**89.3%**	**of Book Value.**		
Rated Breaking Strength ** (book value) :				(L)	11,240 lbf					

- Shaded areas indicate data manually entered or calculated. (Data & Photos Stored in :I:\TDT\LAM 419)

See Page 2 for Test Methods and Specifications. See Page 2 for asterisk (*) and footnote explanations.

Revision 2014-15

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 266.8 kcmil 26/7

KINECTRICS

TEST DATE : Dec 8-11, 2014 **TESTED by :** Geoffrey A / Mike C **KINECTRICS REF. NO. :** 419649 - GLP - 2014 - 02

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY or GPS	RECEIVED DATE
na	No. 3 Sault 155kV Line	495 - 496	Long Section connected to Splice	31-Oct-14

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 266.8 kcmil 26/7 Nom. Cable Diameter ** : 0.642 in

	Alum. Outer Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Min. Breaking Strength for a single wire = 197 lbf	26,000 psi	Min. Breaking Strength for a single wire = 197 lbf	210,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1013 in		0.1013 in		0.0788 in	Min. Breaking Strength of single wire = 1,024 lbf
Area of Wire :	0.0081 sq. in		0.0081 sq. in		0.0049 sq. in	Min. Load @ 1% Elongation = 927 lbf
Number of Wires in Layer :	16		10		7	For Tension Test Load @ 1% Elongation **** : Preload = 71.05 lbf., Offset = 0.005 in.
Number of Wires Tested :	4		4		7	
Minimum Elongation in 10", at Failure, in Percent (%) : ***	1.5 %		1.5 %		3.0 %	

TEST RESULTS

WIRE No.	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %
1	0.81	0.99	6.07
2	0.78	0.70	5.92
3	0.72	1.01	Note 1
4	0.86	0.81	6.09
5	0.81	0.77	5.38
6	0.65	0.82	5.78
7 (core wire)			6.23
Average :	**0.77**	**0.85**	**5.85** (1 to 6)

- Shaded areas indicate data manually entered or calculated.

Tension & Elongation Test Method : ASTM B557-02a for Aluminum wires & ASTM A370-09a for Steel wires.
* Torsion Test Method : ASTM A938-04 (Using 1% of Nominal Breaking Strength of wire for Tension load).
** Wire & Cable Diameters and Rated Breaking Strength taken from Ontario Hydro ACSR Conductor data catalogue.
*** Values for Aluminum wires from ASTM B230-07 Table 1, and for Steel wires from ASTM B498-08 Table 2.
**** Values for 1% Elongation from CSA CAN3-C49.6-M85, Table 2.
***** Derating values from Southwire Overhead Conductor Manual, Table 1-14.

[1] 'Category' from Table 2, Page 3.
[2] 'Rating' from Table 3, Page 3
[3] 'Remaining Zinc' from Table 1 (H), Page 3

Note 1 : During measurement, wire broke before extensiometer was removed, unable to obtain an elongation value.

Revision 2014-15

ACSR 266.8 kcmil 26/7, CCT : na, Line Section : No. 3 Sault 155kV Line, Structure No.: 495 - 496

TABLE 1

Remaining Zinc on Steel and Core Wires										
	Measured Data				Calculated Data					
Wire No.	Wgt. of Wire Before Stripping (g) (A)	Ave. Dia. Before Stripping (mm) (B)	Wgt. of Wire After Stripping (g) (C)	Ave. Dia. After Stripping (mm) (D)	Zinc Thickness (before - after) (mm) (B - D)	Zinc Thickness (Calculated by Weight) (mm) (E)	Zinc Removed (before - after) (g) (A - C)	Zinc Weight [mass] of coating (g/m^2) (F)	Percent Zinc vs. Core Wire % (F/G)
1	9.070	1.95	8.597	1.88	0.04	0.03	0.473	203	73
2	9.549	1.99	9.010	1.92	0.04	0.03	0.539	225	82
3	9.260	1.99	8.695	1.90	0.05	0.03	0.565	241	87
4	8.978	1.95	8.455	1.85	0.05	0.03	0.523	224	81
5	9.188	1.97	8.632	1.88	0.05	0.03	0.556	237	86
6	9.375	1.97	8.857	1.89	0.04	0.03	0.518	217	78
Avg. of 1 to 6	9.237	1.97	8.708	1.89	0.04	0.03	0.529	225	81 (H)
7 (core wire)	9.923	2.02	9.248	1.93	0.05	0.04	0.675	276 (G)	100

Remaining Zinc Test Method : ASTM A90M-01 for Weight [Mass] of Coating on Iron and Steel Articles with Zinc or Zinc-Alloy Coatings.

Column F = (A-C)/C*D*1960 Column E = F/7140 kg/m^3 Note : Zinc Thickness values in Column E are rounded off to two(2) decimals.

Note : Samples length are approximately 16 inches (406 mm).

TABLE 2

"EXTENT" of Rust on 'Outer Surface' of Steel Wires	
Kinectrics Category	Percent of Rust by Area
Stage 1	none (0 %)
Stage 2 a	>0 - 33 %
Stage 2 b	33 - 66 %
Stage 2 c	66 - <100 %
Stage 3	100%

TABLE 3

"SEVERITY" of Rust on 'Outer Surface' of Steel Wires	
Rating	Steel Wire Surface Condition
1	No Rust, 100% galvanized
2	Light surface rust and negligible pitting
3	Moderate surface rust with mild pitting
4	Heavy surface rust with mild to moderate pitting
5	Heavy surface rust with moderate to heavy pitting

Steel Wires refers to the outer steel layer.
Core Wire refers to the single wire at the centre of the steel wires.

Prepared by: Mike Colbert

M. Colbert
Technologist
Transmission & Distribution Technologies

Approved by: Dmitry Ladin

D. Ladin
Principal Engineer/Scientist
Transmission & Distribution Technologies

AAC 266.8 kcmil, 26/7. CCT : na, Line Section : No. 3 Sault 155kV Line, Structure No.: 495 - 496

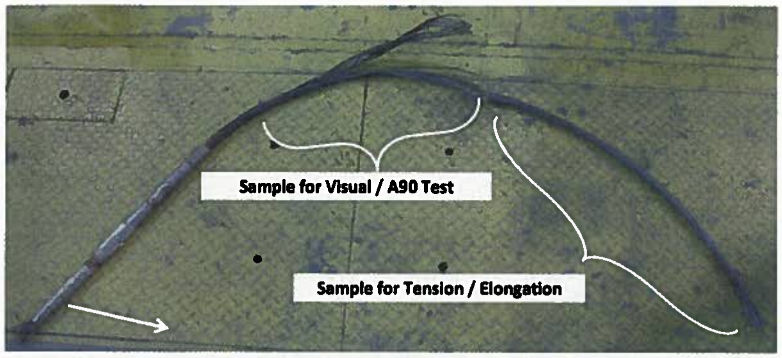


Figure 1 - Samples for Testing

Figure 2a - Outer Surface - Darker Contaminated Side

Figure 2b - Outer Surface - Darker Contaminated Side - Close-up

Figure 2c - Outer Surface - Darker Contaminated Side - Close-up of Melted Spot

Figure 3a - Outer Surface - Grey Side

Figure 3b - Outer Surface - Grey Side - Close-up

Figure 3c - Outer Surface - Grey Side - Close-up of Melted Spot

Figure 3d - Outer Surface - Grey Side - Close-up of Melted Spot

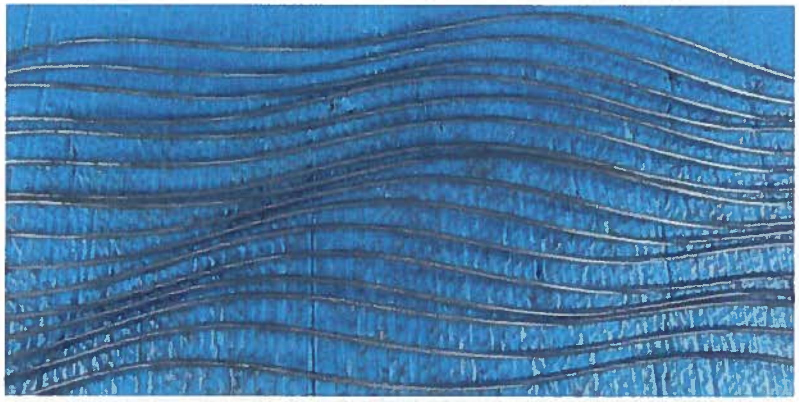


Figure 4a - Outer Layer Wires

Figure 4b - Outer Layer Wires - Inner Surface - Close-up

Figure 5a - Inner Layer - Outer Surface - Darker Contaminated Side

Figure 5b - Inner Layer - Outer Surface - Darker Contaminated Side - Close-up

Figure 6 - Inner Layer - Outer Surface - Lighter Contaminated Side

Figure 7a - Inner Layer - Outer Surface - Lighter Contaminated Side - Close-up

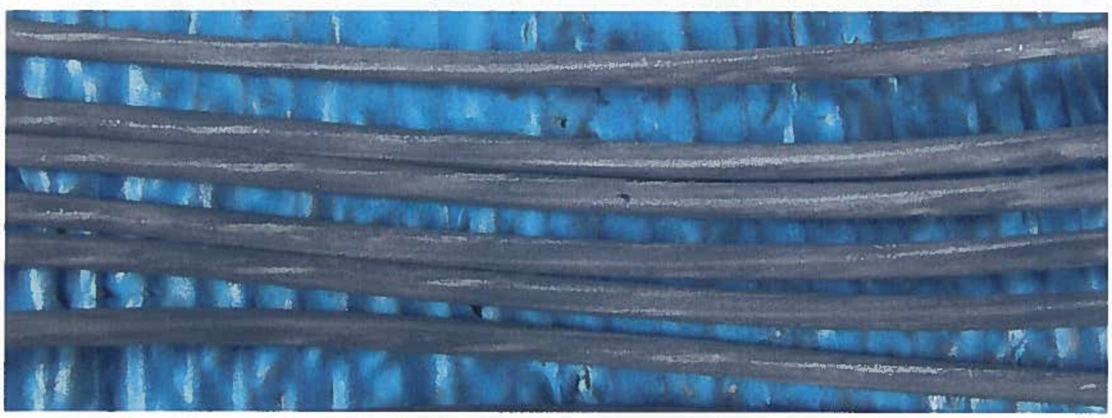


Figure 7b - Inner Layer Wires

Figure 8a - Steel Wires - Outer Surface

Figure 8b - Steel Wires

Figure 8c - Steel Wires - Close-up

Figure 8d - Steel Wires - Outer Surface of Two Wires after Removing Zinc

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 266.8 kcmil 26/7

KINECTRICS

TEST DATE :	Dec 11-16, 2014	TESTED by :	Mike C	KINECTRICS REF. NO. :	419649 - GLP - 2014 - 03

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	DEVICE	RECEIVED DATE
na	No. 3 Sault 155kV Line	495 - 496	Aluminum Splice Assembly	31-Oct-14

VISUAL OBSERVATIONS of SPLICE (ALUMINUM and STEEL)

Note : For the observations, the notation "Failed Side" refers to the end of the splice with the burnt/broken conductor. The Non-Failed is the opposite end. Figure 1.

ALUMINUM SPLICE & WIRES :

Aluminum Splice :
1) The Failed side had 9 crimped locations. They were not equally spaced. Gaps ranged from 3/16" to 3/8" between crimps. Figure 1a.
2) The Non-Failed side had 9 crimped locations. They were not equally spaced. Gaps ranged from 1/8" to 3/8" between crimps. Figure 1b.
3) Both Failed and Non-Failed inside surfaces had burn marks. Figures 2a and 2b.

Aluminum Wires :
1) Both Failed and Non-Failed outer aluminum layer surface had many burnt looking spots in the same locations as the splice inside surface. Figures 2a and 2b.
2) Failed side aluminum wires were all burnt and broken about 1" to 1 1/2" outside of the splice opening. Figure 3a.
3) Non-Failed side of splice had 3 aluminum wires that had necked and broke, about 1" inside from opening. Figure 3b.

Steel Wires :
1) On the Failed Side - Five steel wires were burnt/broken about 1" inside splice opening. The other two steel wires were burnt/broken about 2.5" outside the splice opening. Figure 4.
2) On both ends of splice - The outer layer steel wires were heavily rusted and had loss of material. Some wires broke during disassembly. Figure 5.

STEEL WIRE SPLICE & WIRES :
1) The steel splice was very rusted. Could not indentify location and spacing of crimps due to loss of material. Figure 6.
2) All steel wires were intact and positioned correctly inside splice. There was a 1/4" space between the ends of the wires at center. Figure 7.
3) The 6 outer layer wires had light rust/corrosion on both Failed and Non-Failed sides. The core wire had some very light corrosion. Figure 8.

CONDUCTOR, Failed Side - 2 1/2 foot Sample, and Non-Failed Side :
1) The Failed Side - 2 1/2 foot sample is shown in Figure 9. The aluminum wires had small burn marks scattered sporatically along it's length.
2) The Non-Failed Side is shown in Figure 10.
3) On both the Failed and Non-Failed Sides, the steel wires had moderate to heavy rust/corrosion starting at the aluminum splice mouth. Figure 11. This continued outward for about 10". Then there was a gradual transition to no corrosion (zinc intact).
4) Failed Side - Wires exiting aluminum splice mouth, had moderate to heavy rust. Figure 12a. Wires beyond 10" location, no corrosion. Figure 12b.
5) Non-Failed Side - Wires exiting aluminum splice mouth, had moderate to heavy rust. Figure 13a. Wires at 10" location, corrosion almost gone. Figure 13b.

Prepared by: Mike Colbert

M. Colbert
Technologist
Transmission & Distribution Technologies

Approved by: Dmitry Ladin

D. Ladin
Principal Engineer/Scientist
Transmission & Distribution Technologies

Y35 PRESS USED (DISTRIBUTION

60 TON PRESS SHOULD BE USED

ACSR 266.8 kcmil, 26/7. CCT : na, Line Section : No. 3 Sault 155kV Line, Structure No.: 495 - 496

IMPLODES ARE BEST.

Figure 1 - Aluminum Splice

Figure 1a - Failed Side Crimp Locations

Figure 1b - Non-Failed Side Crimp Locations

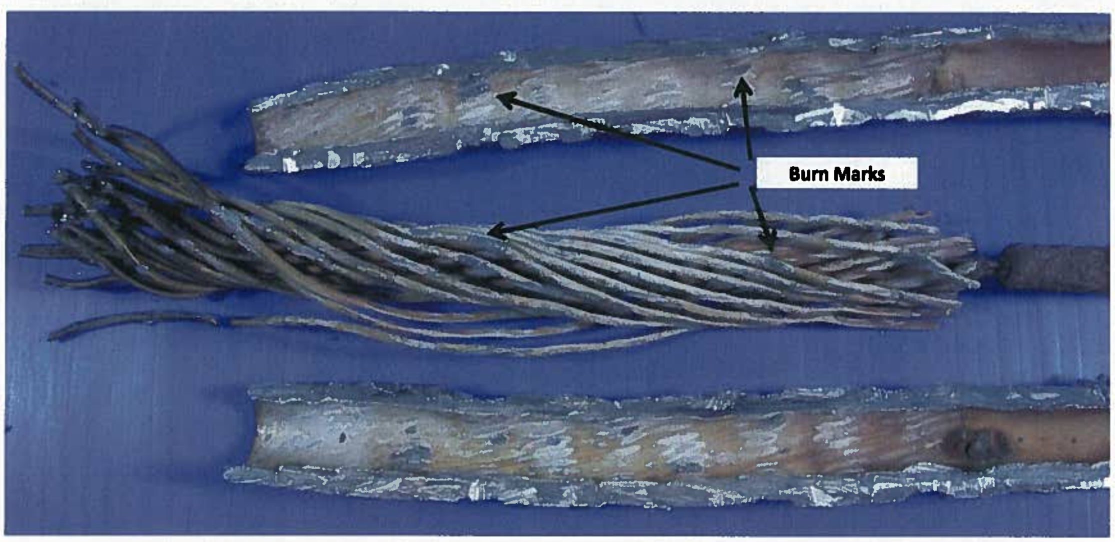


Figure 2a - Failed Side - Burn marks on Alum Wires and Splice Inner Surface

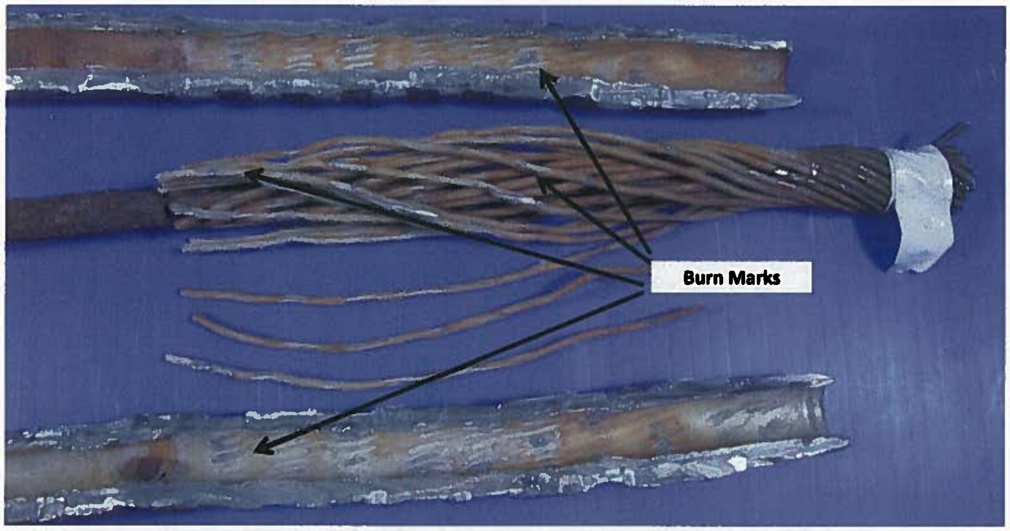


Figure 2b - Non-Failed Side - Burn marks on Alum Wires and Splice Inner Surface

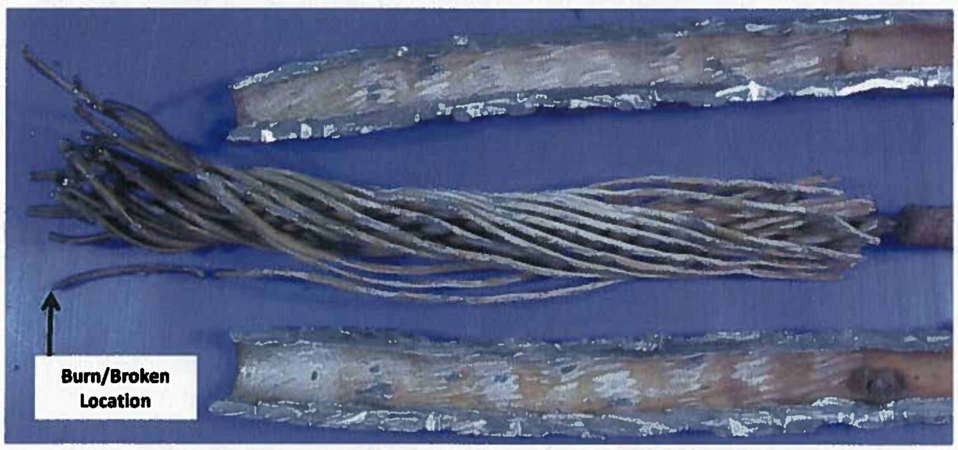


Figure 3a - Failed Side - Burn and Broken Wires Outside Splice Opening

Figure 3b - Non-Failed Side - Three Broken Aluminum Wires Inside Splice

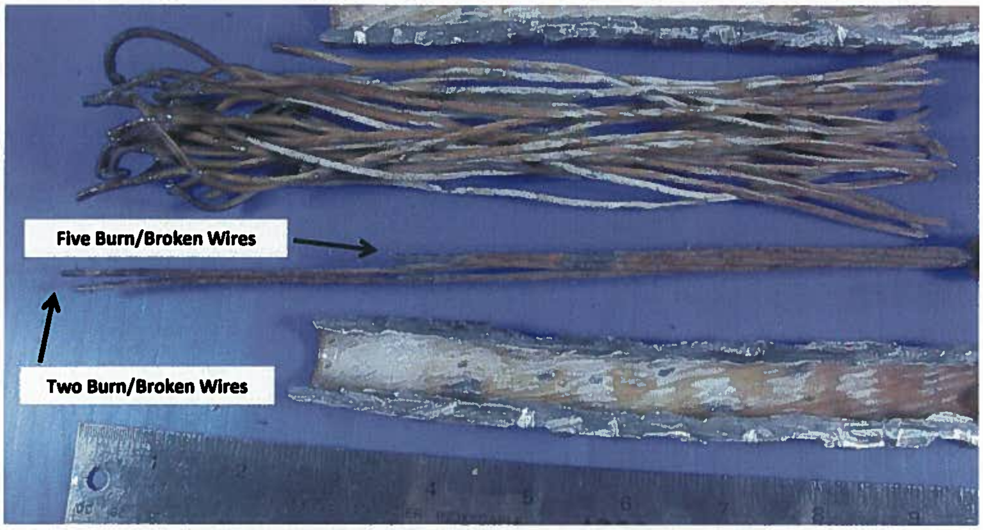


Figure 4 - Failed Side - Burnt/Broken Wires

Figure 5 - Failed Side - Heavily Rusted Steel Wires at Mouth of Splice

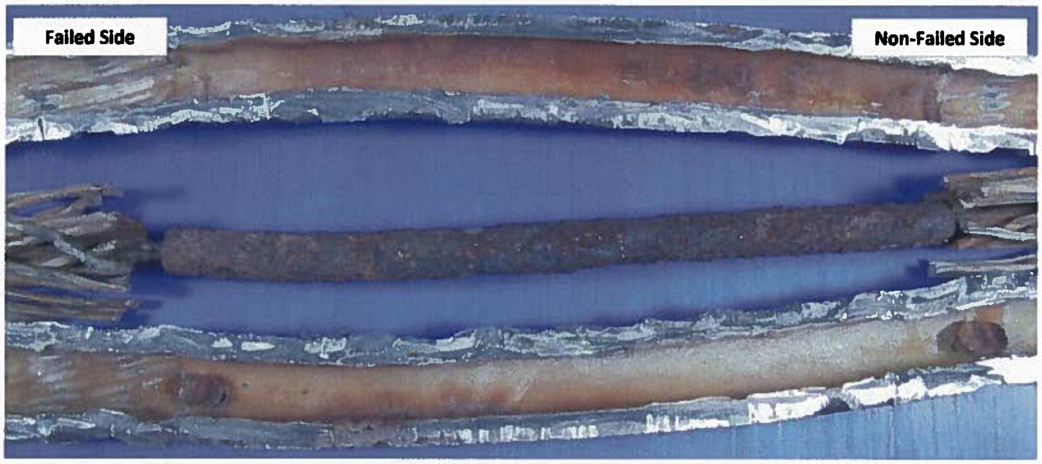


Figure 6 - Steel Wires Inside Splice

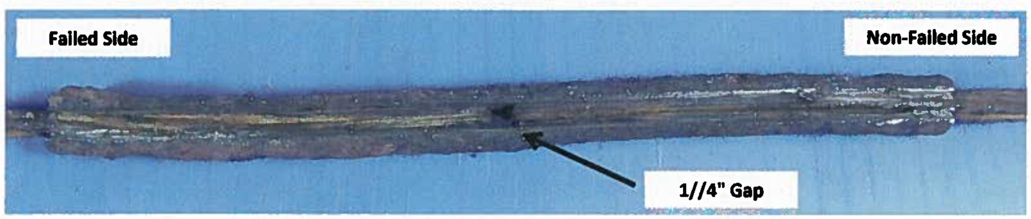


Figure 7 - Steel Wires from Inside the Splice

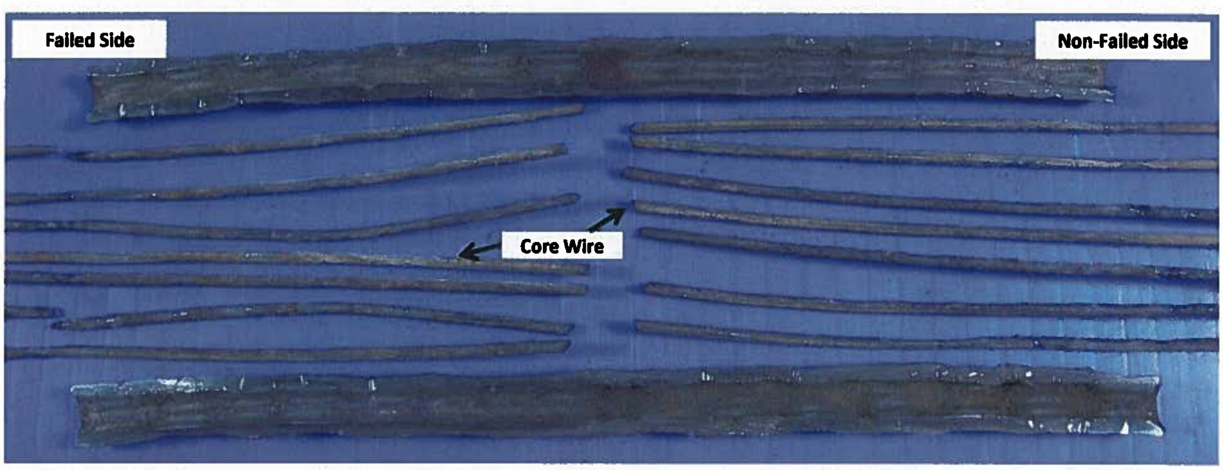


Figure 8 - Steel Wires from Inside the Splice

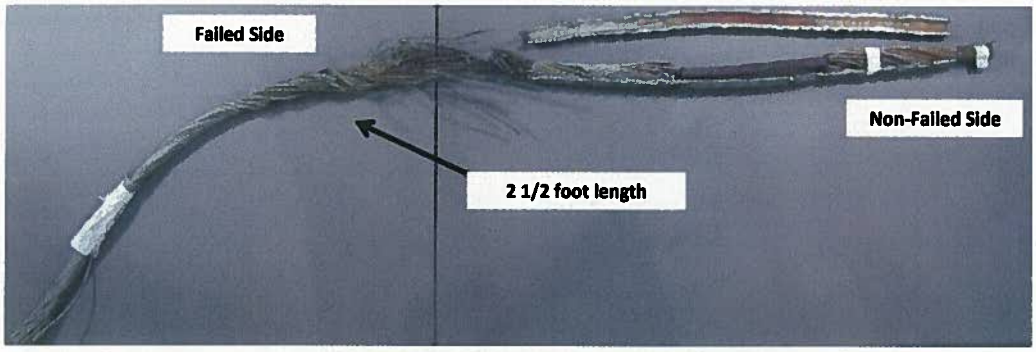


Figure 9 - Failed Side - 2 1/2 foot Sample

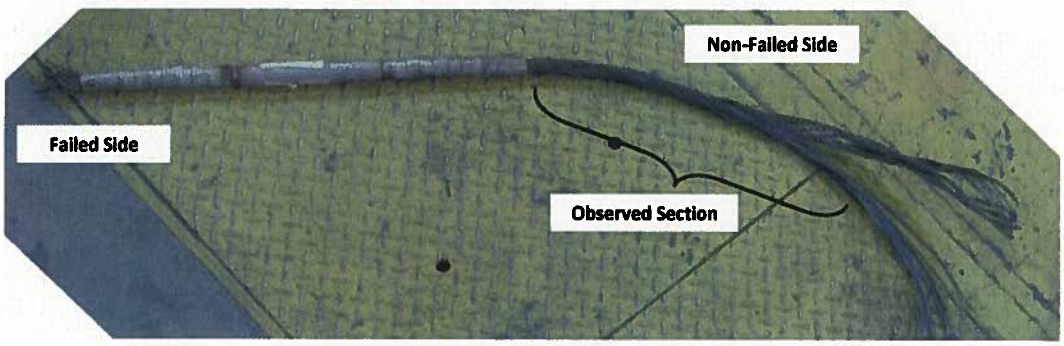


Figure 10 - Non-Failed Side

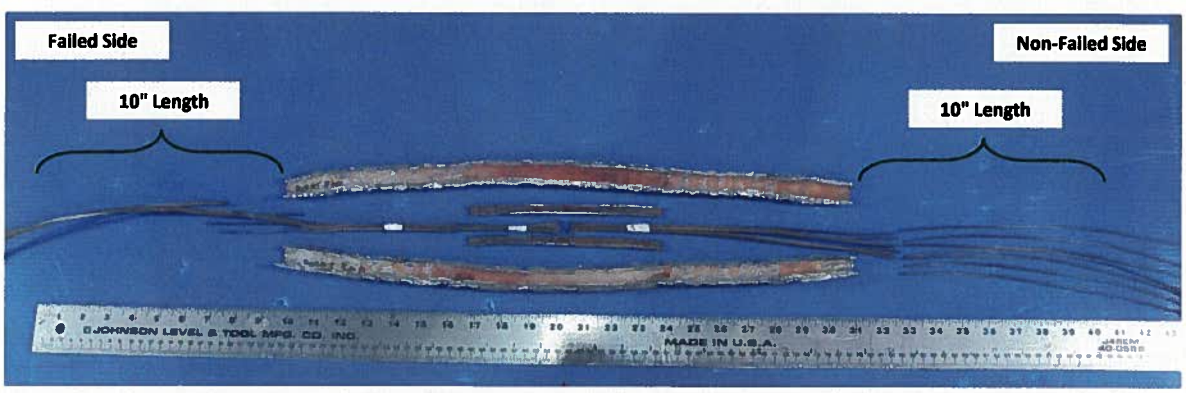


Figure 11 - Location of Moderate to Heavy Rust Sections on both ends of Splice

Figure 12a - Failed Side - Moderate to Heavy Rusted Wires (for about 10 inch length)

Figure 12b - Failed Side - Wires Beyond 10 inch Location, No Corrosion

Figure 13a - Non-Failed Side - Moderate to Heavy Rusted Wires 2" from Splice Mouth

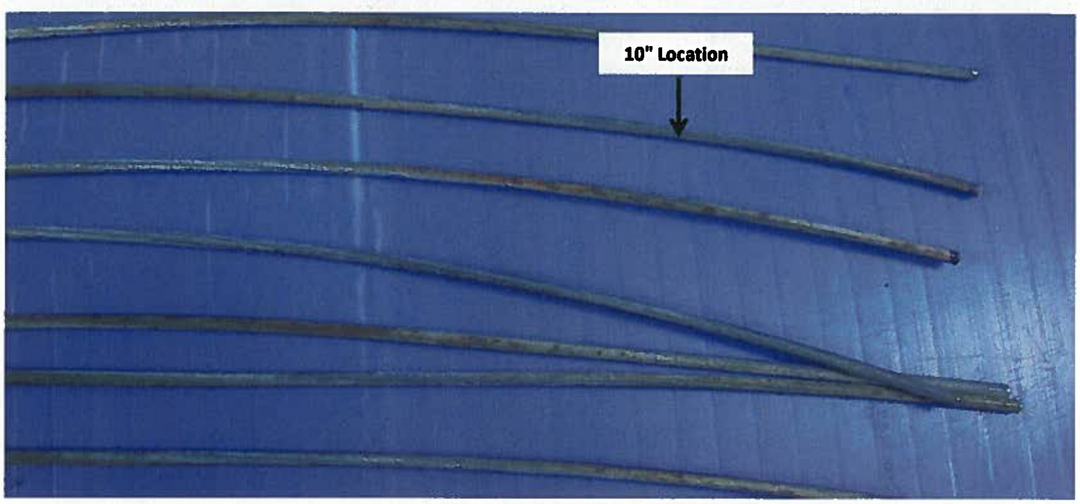


Figure 13b - Non-Failed Side - Around 10 inch Location, Corrosion Almost Gone

APPROX STR 165

THIS CONDUCTOR IN GOOD COND.

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 266.8 kcmil 26/7

TEST DATE : Dec 4-8, 2014 TESTED by : Geoffrey A / Mike C KINECTRICS REF. NO. : 419649 - GLP - 2014 - 01

KINECTRICS

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY or GPS	RECEIVED DATE
Stockley	No. 3 Sault 155kV Line	not available	not available	31-Oct-14

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 266.8 kcmil 26/7 Nom. Cable Diameter ** : 0.642 in Measured Cable Diameter : 0.657 in

	Alum. Outer Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Min. Breaking Strength	26,000 psi	Min. Breaking Strength	210,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1013 in	for a single wire = 197 lbf	0.1013 in	for a single wire = 197 lbf	0.0788 in	Min. Breaking Strength of single wire = 1,024 lbf
Area of Wire :	0.0081 sq. in		0.0081 sq. in		0.0049 sq. in	Min. Load @ 1% Elongation = 927 lbf
Number of Wires in Layer :	16		10		7	For Tension Test Load @ 1% Elongation **** :
Number of Wires Tested :	4		4		7	Preload = 71.05 lbf., Offset = 0.005 in.
Tension Load for Torsion Test * :	1.97 lbf	= 0.896 kgf	1.97 lbf	= 0.896 kgf	10.24 lbf	= 4.645 kgf
Torsion Test sample length * :	14.66 in	= (120 x dia. + 2.5")	14.66 in	= (120 x dia. + 2.5")	11.96 in	= (120 x dia. + 2.5")

TEST RESULTS

Measured Wire Diameter : (for identification only)	0.9950 in			0.1000 in			0.0785 in (use core wire)				Remaining Zinc [3]
	The outer surface of the alum. wires had :			The outer surface of the alum. wires had :			The outer surface of the steel wires had :				% Zinc (avg of wires 1-6) vs. Core Wire
	Contam	Pitting	Color	Contam	Pitting	Color	Category [1]	Rating [2]	Rust	Pitting	
	light	none	grey/black	light	none	brown/black	2b	2	light	mild	79%

Comments :

- Alum. Outer Layer: The outer surface had fixed black contamination on one side. It rubbed off with brillo pad. Very mild surface corrosion underneath. The other side was grey with very mild surface corrosion. The inner surface had dark fixed contam & fret marks on one side. The other side had brown fixed dirt contam & fret marks. Both rubbed off with brillo pad to a clean surface.
- Alum. Inner Layer: The outer surface had fixed black contam on one side, and loose & fixed dirt contam on the other. Both rubbed off to clean surface. Had fret marks. The inner surface had loose & fixed dirt & brown contam over the entire surface. Rubbed off to good surface. Some fret marks had white contam on and around them.
- Steel and Core Wires: The outer surface had areas of brown and white contamination, indicating corrosion. After removing zinc coating, mild corrosion and pitting were observed. The inner surface had some areas of white contam indicating corrosion of zinc. Other areas the zinc was intact. No corrosion observed after A90 test. The core wire had some areas of white contam indicating corrosion of zinc. Other areas the zinc was intact. No corrosion after A90 test.

WIRE No.	Alum. Outer: Number of Turns	Breaking Strength lbf	Breaking Strength psi (calc)	Alum. Inner: Number of Turns	Breaking Strength lbf	Breaking Strength psi (calc)	Steel: Number of Turns	Load @ 1% Elongation, lbf	Breaking Strength lbf	Breaking Strength psi (calc)
1	75.8	194	24,071	53.8	188	23,326	17.6	930	1064	218,172
2	73.7	182	22,582	56.8	197	24,443	18.3	841	948	194,386
3	63.2	195	24,195	66.9	196	24,319	14.9	873	990	202,999
4	62.8	215	26,677	89.0	181	22,458	11.9	927	1046	214,481
5	-	-	-	-	-	-	16.3	928	1041	213,456
6	-	-	-	-	-	-	17.7	868	977	200,333
7 (core wire)	-	-	-	-	-	-	21.9	927	1054	216,122
Average (Steel & Core 'No. of Turns' is Avg. 1 to 6) :	68.9	197	24,381	66.6	191	23,637	16.1	899	1,017	208,564
Avg.Strength x # of Wires in Layer :	(A)	3,144 lbf		(B)	1,905 lbf					
Measured Strength (Alum/Steel) :		A+B=(C)	5,049 lbf					(D)	7,120 lbf	
Calculated Total Strength of Layer :	(E)	3,353 lbf		(F)	2,095 lbf			(G)	7,169 lbf	
Measured / Calculated (%) :	A/E =	93.8%		B/F =	90.9%			D/G =	99.3%	
Total Load on Steel @ 1% Elongation :							(H)	6,294 lbf	= 97.0% of Nom 1% Load	
Total Measured Breaking Strength :			C+H=(J)	11,343 lbf	=	100.9% of Book Value.				
Derated Meas. Breaking Strength ***** :			(K)	10,738 lbf	=	95.5% of Book Value.				
Rated Breaking Strength ** (book value) :			(L)	11,240 lbf						

- Shaded areas indicate data manually entered or calculated. (Data & Photos Stored in :I:\TDT\LAM 419)

See Page 2 for Test Methods and Specifications. See Page 2 for asterisk (*) and footnote explanations. Revision 2014-15

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 266.8 kcmil 26/7

KINECTRICS

TEST DATE :	Dec 4-8, 2014	TESTED by :	Geoffrey A / Mike C	KINECTRICS REF. NO. :	419649 - GLP - 2014 - 01

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY or GPS	RECEIVED DATE
Stockley	No. 3 Sault 155kV Line	not available	not available	31-Oct-14

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 266.8 kcmil 26/7 Nom. Cable Diameter ** : 0.642 in

	Alum. Outer Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Min. Breaking Strength for a single wire = 197 lbf	26,000 psi	Min. Breaking Strength for a single wire = 197 lbf	210,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1013 in		0.1013 in		0.0788 in	Min. Breaking Strength of single wire = 1,024 lbf
Area of Wire :	0.0081 sq. in		0.0081 sq. in		0.0049 sq. in	Min. Load @ 1% Elongation = 927 lbf
Number of Wires in Layer :	16		10		7	For Tension Test Load @ 1% Elongation **** : Preload = 71.05 lbf., Offset = 0.005 in.
Number of Wires Tested :	4		4		7	
Minimum Elongation in 10", at Failure, in Percent (%) : ***	1.5 %		1.5 %		3.0 %	

TEST RESULTS

WIRE No.	Alum. Outer Layer: Elongation in 10 " at Failure, Percent %	Alum. Inner Layer: Elongation in 10 " at Failure, Percent %	Steel and Core Wires: Elongation in 10 " at Failure, Percent %
1	1.07	0.85	4.95
2	1.46	0.93	4.67
3	1.13	0.83	4.81
4	1.31	0.96	5.07
5			4.13
6			4.09
7 (core wire)			5.62
Average :	1.24	0.89	4.62 (1 to 6)

- Shaded areas indicate data manually entered or calculated.

Tension & Elongation Test Method : ASTM B557-02a for Aluminum wires & ASTM A370-09a for Steel wires.
* Torsion Test Method : ASTM A938-04 (Using 1% of Nominal Breaking Strength of wire for Tension load).
** Wire & Cable Diameters and Rated Breaking Strength taken from Ontario Hydro ACSR Conductor data catalogue.
*** Values for Aluminum wires from ASTM B230-07 Table 1, and for Steel wires from ASTM B498-08 Table 2.
**** Values for 1% Elongation from CSA CAN3-C49.6-M85, Table 2.
***** Derating values from Southwire Overhead Conductor Manual, Table 1-14.

[1] 'Category' from Table 2, Page 3.
[2] 'Rating' from Table 3, Page 3
[3] 'Remaining Zinc' from Table 1 (H), Page 3

Revision 2014-15

ACSR 266.8 kcmil 26/7, CCT : Stockley, Line Section : No. 3 Sault 155kV Line, Structure No.: not available

TABLE 1

Remaining Zinc on Steel and Core Wires									
Measured Data					Calculated Data				
Wire No.	Wgt. of Wire Before Stripping (g) (A)	Ave. Dia. Before Stripping (mm) (B)	Wgt. of Wire After Stripping (g) (C)	Ave. Dia. After Stripping (mm) (D)	Zinc Thickness (before - after) (mm) (B - D)	Zinc Thickness (Calculated by Weight) (mm) (E)	Zinc Removed (before - after) (g) (A - C)	Zinc Weight [mass] of coating (g/m^2) (F)	Percent Zinc vs. Core Wire % (F/G)
1	9.648	2.01	9.176	1.92	0.04	0.03	0.472	194	76
2	10.373	2.00	9.727	1.94	0.03	0.04	0.646	253	99
3	9.641	2.00	9.161	1.91	0.05	0.03	0.480	196	77
4	9.515	1.99	9.015	1.90	0.05	0.03	0.500	207	81
5	10.016	1.99	9.550	1.90	0.05	0.03	0.466	182	72
6	9.182	1.94	8.768	1.87	0.03	0.02	0.414	173	68
Avg. of 1 to 6	9.729	1.99	9.233	1.91	0.04	0.03	0.496	201	79 (H)
7 (core wire)	9.727	2.00	9.112	1.92	0.04	0.04	0.615	254 (G)	100

Remaining Zinc Test Method : ASTM A90M-01 for Weight [Mass] of Coating on Iron and Steel Articles with Zinc or Zinc-Alloy Coatings.

Column F = (A-C)/C*D*1960 Column E = F/7140 kg/m^3 Note : Zinc Thickness values in Column E are rounded off to two(2) decimals.

Note : Samples length are approximately 16 inches (406 mm).

TABLE 2

"EXTENT" of Rust on 'Outer Surface' of Steel Wires	
Kinectrics Category	Percent of Rust by Area
Stage 1	none (0 %)
Stage 2 a	>0 - 33 %
Stage 2 b	33 - 66 %
Stage 2 c	66 - <100 %
Stage 3	100%

TABLE 3

"SEVERITY" of Rust on 'Outer Surface' of Steel Wires	
Rating	Steel Wire Surface Condition
1	No Rust, 100% galvanized
2	Light surface rust and negligible pitting
3	Moderate surface rust with mild pitting
4	Heavy surface rust with mild to moderate pitting
5	Heavy surface rust with moderate to heavy pitting

Steel Wires refers to the outer steel layer.
Core Wire refers to the single wire at the centre of the steel wires.

Prepared by: Mike Colbert

M. Colbert
Technologist
Transmission & Distribution Technologies

Approved by: Dmitry Ladin

D. Ladin
Principal Engineer/Scientist
Transmission & Distribution Technologies

AAC 266.8 kcmil, 26/7. CCT : Stockley, Line Section : No. 3 Sault 155kV Line, Structure No.: not available

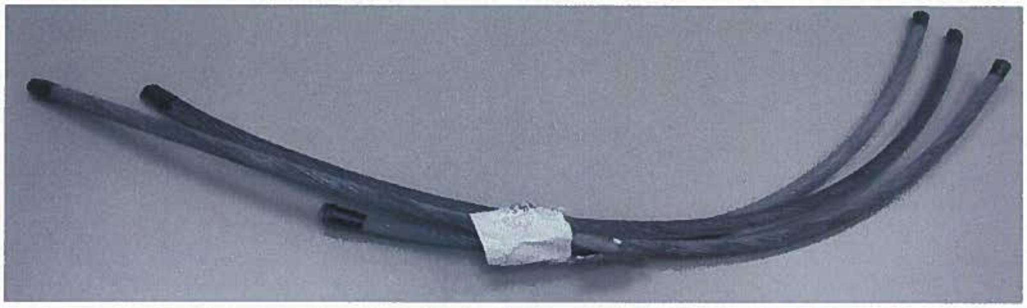


Figure 1 - Samples for Testing

Figure 2a - Outer Surface - Darker Contaminated Side

Figure 2b - Outer Surface - Darker Contaminated Side - Close-up

Figure 3a - Outer Surface - Grey Side

Figure 3b - Outer Surface - Grey Side - Close-up

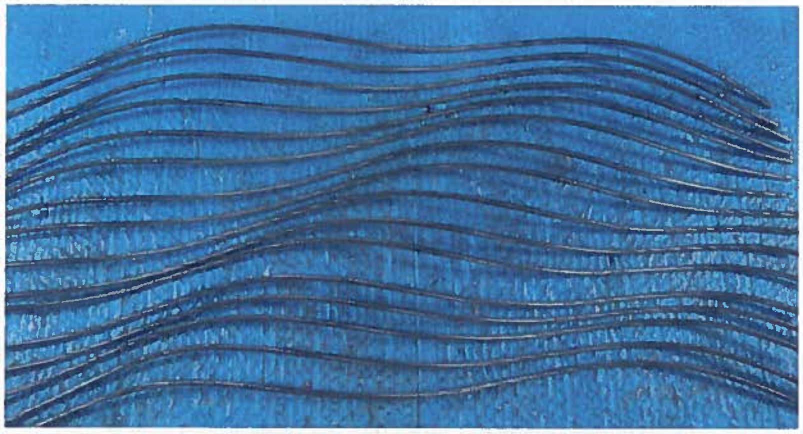


Figure 4a - Outer Layer Wires

Figure 4b - Outer Layer Wires - Inner Surface - Close-up

Figure 5a - Inner Layer - Outer Surface - Darker Contaminated Side

Figure 5b - Inner Layer - Outer Surface - Darker Contaminated Side - Close-up

Figure 6a - Inner Layer - Outer Surface - Lighter Contaminated Side

Figure 6b - Inner Layer - Outer Surface - Lighter Contaminated Side - Close-up

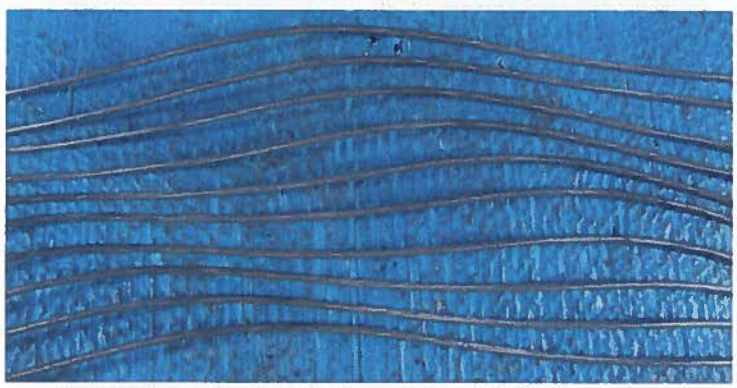


Figure 7a - Inner Layer Wires

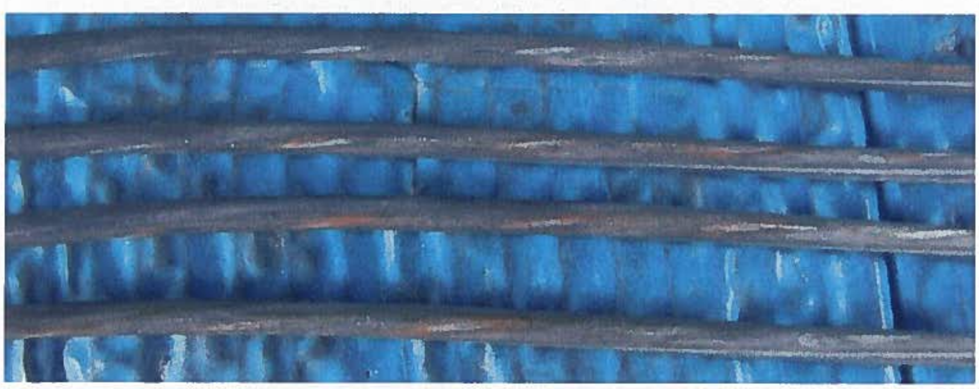


Figure 7b - Inner Layer - Inner Surface - Close-up

AAC 266.8 kcmil, 26/7. CCT : Stockley, Line Section : No. 3 Sault 155kV Line, Structure No.: not available

Figure 8a - Steel Wires

Figure 8b - Steel Wires - Close-up

Figure 8c - Steel Wires - Inner Surface (top) & Outer Surface (bottom)

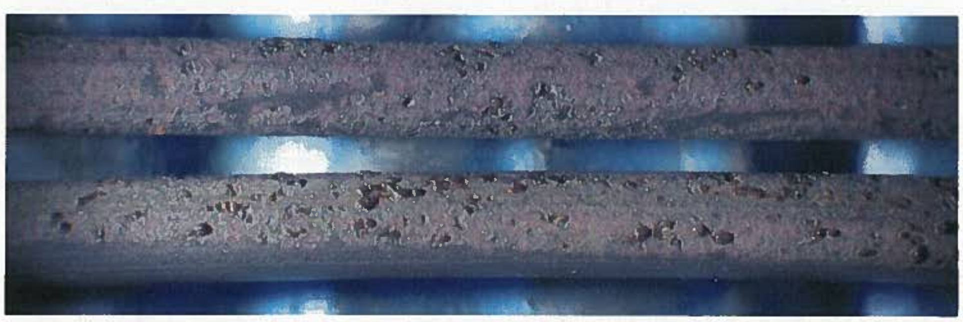


Figure 8d - Steel Wires - Outer Surface of Two Wires after Removing Zinc

NEEDS ASSESSMENT REPORT

East Lake Superior Region

Revision: FINAL R0
Date: December 12, 2014

Prepared by: East Lake Superior Region Study Team

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the East Lake Superior Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Great Lakes Power Transmission LP (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT SUMMARY REPORT

NEEDS ASSESSMENT SUMMARY REPORT			
NAME	East Lake Superior Region Study		
LEAD	Great Lakes Transmission LP (GLPT)		
REGION	East Lake Superior		
START DATE	October 12, 2014	**END DATE**	December 12, 2014

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the East Lake Superior Region (ELS-Region), determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a “wires” only solution is necessary such needs will be addressed among the relevant Local Distribution Companies (LDCs), GLPT and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution) is required, or whether both are required.

2. REGIONAL ISSUES/TRIGGER

The Needs Assessment for the East Lake Superior Region was triggered in response to the Ontario Energy Board’s (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario’s 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. East Lake Superior Region belongs to Group 2 and the Needs Assessment for this Region was triggered on October 12, 2014 and was completed on December 12, 2014.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023. Needs emerging over the near-term (0-5 years) and mid-term (6-10 years) should be further assessed as part of the OPA-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year plan and strategic direction for the Region.

The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans.

4. INPUTS/DATA (INFORMATION REQUIRED TO COMPLETE ASSESSMENT)

Study team participants, including representatives from Local Distribution Companies (LDC), the Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO) and Hydro One Networks Inc. (Hydro One) provided information and input to GLPT for the East Lake Superior Region. The information provided includes the following:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

5. ASSESSMENT

The assessment's primary objective over the study period (2014 to 2023) is to identify the electrical infrastructure needs in the region. The study reviewed available information, load forecast and conducted single contingency analysis to confirm need, if and when required. See Section 5 for further details.

6. RESULTS

A. 230kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at the one 230kV connected load station throughout the study period. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

- Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

- East-West Tie lines are to be upgraded within the time period of this Needs Assessment. Hydro One's Customer Impact Assessment (CIA) entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customer in the area.

B. 230/115kV Autotransformers

- No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

C. 115kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

- Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the increased demand forecast from one large industrial customer in Sault Ste. Marie projecting an increase in peak. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

D. System Reliability, Operation and Restoration Review

- Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

- There is a concern about transformer failure in the region where there are some load stations with just one transformer supplying customer load. The Ontario Resource and Transmission Assessment Criteria (ORTAC) restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

E. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)

- Tarentorus TS (equipment & relaying)

7. RECOMMENDATION

The Team Recommends:

The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution continue to be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

The potential needs identified regarding the capacity of the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS do not require further regional coordination. The study team recommends that a "localized wire only solution be developed in the near-term to address the above need through planning between GLPT and the impacted customer.

The potential need identified for the restoration of load (ORTAC 8 hours violated) after a single supply transformer failure does not require further regional coordination. The study team recommends that a "localized" wire only solution be developed by GLPT and the impacted distributor.

PREPARED BY: East Lake Superior Region Study Team

PARTICIPANTS: LISTED BELOW

COMPANY	NAME
Great Lakes Power Transmission LP (Lead)	**Jim Tait**
Ontario Power Authority	**Bob Chow**
Independent Electricity System Operator	**Phillip Woo**
Hydro One Networks Inc. (Transmitter)	**Ajay Garg**
PUC Distribution Inc.	**Rob Harten**
Algoma Power Inc.	**Greg Beharriell**
Chapleau Public Utility Corporation	**Alan Morin**

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

1. INTRODUCTION

This Needs Assessment report identifies needs in the East Lake Superior Region ("ELS-Region"). For needs that require coordinated regional planning, the OPA will initiate the Scoping process to determine the appropriate regional planning approach. The approach can either be the OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP), which focuses on the development of "wires" solutions. It may also be determined that the needs can be addressed more directly through localized planning between the transmitter and the specific distributor(s) or transmission connected customer(s). The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements.

This report was prepared by the ELS-Region Needs Assessment study team (Table 1) and led by the transmitter, Great Lakes Power Transmission LP (GLPT). The report captures the results of the assessment based on information provided by the Local Distribution Companies (LDCs), Ontario Power Authority (OPA), Hydro One Network Inc. and the Independent Electricity System Operator (IESO) to determine possible needs in the ELS-Region.

Table 1: Study Team Participants for ELS-Region

Company
Great Lakes Power Transmission LP (GLPT) (Lead Transmitter)
Ontario Power Authority (OPA)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Hydro One) (Transmitter)
PUC Distribution Inc. (PUC)
Algoma Power Inc. (API)
Chapleau Public Utility Corporation (CPUC)

Figure 1: East Lake Superior Region

2. REGIONAL ISSUE / TRIGGER

The Needs Assessment for the ELS-Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. The ELS-Region belongs to Group 2. The Needs Assessment for this ELS-Region was triggered on October 12, 2014 and was completed on December 12, 2014.

Additional information about Regional Planning can be found on the GLPT website:
http://www.glp.ca/content/regional_planning_new/history-40236.html

3. SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the ELS-Region over an assessment period of 2014 to 2023. The scope of the Needs Assessment includes a review of system capability which covers transformer station loading and transmission thermal and voltage analysis based on recent detailed studies. Asset sustainment issues and other considerations were taken into account as deemed necessary.

3.1. EAST LAKE SUPERIOR REGION DESCRIPTION AND CONNECTION CONFIGURATION

Figure 2a – Wawa TS/Anjigami TS Northern Area – Hydro One 230/115 kV autotransformers at Wawa TS, Hydro One 115 kV circuit supplying CPUC load and GLPT 115 kV lines and stations connected via Anjigami TS.

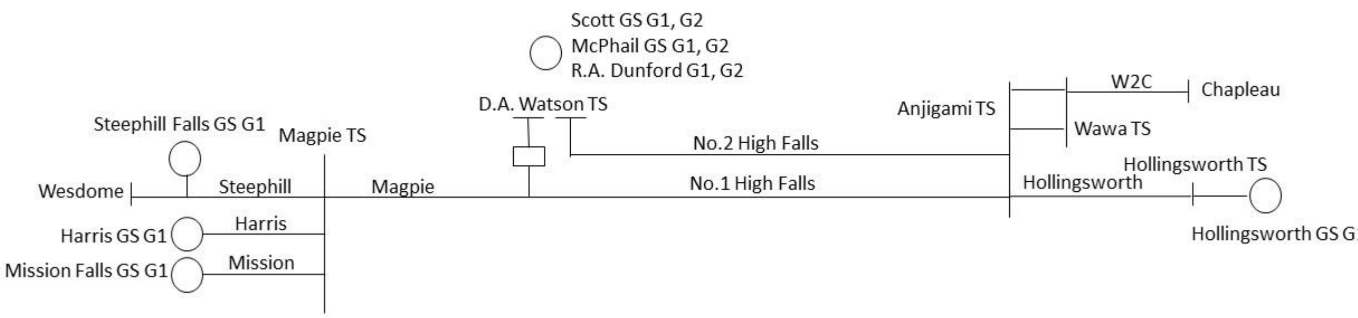


Figure 2b – MacKay TS South Central Area – GLPT 230/115 kV autotransformer at Mackay TS and 115 kV lines/stations connected via Mackay TS and two transformer stations connected to No.3 Sault.

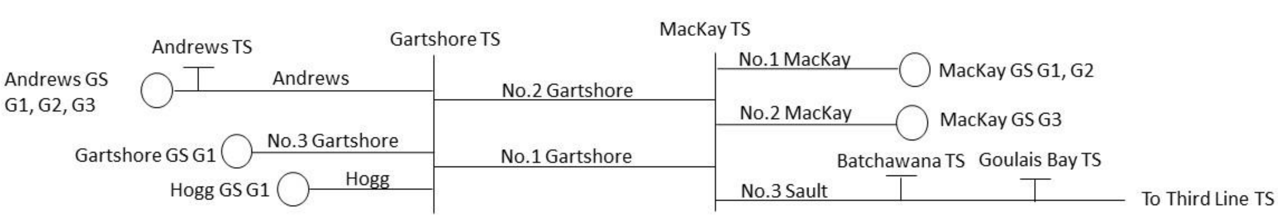


Figure 2c – Sault Ste. Marie Southern Area – GLPT 230/115 kV autotransformers at Third Line TS and 115 kV lines/stations in Sault Ste. Marie.

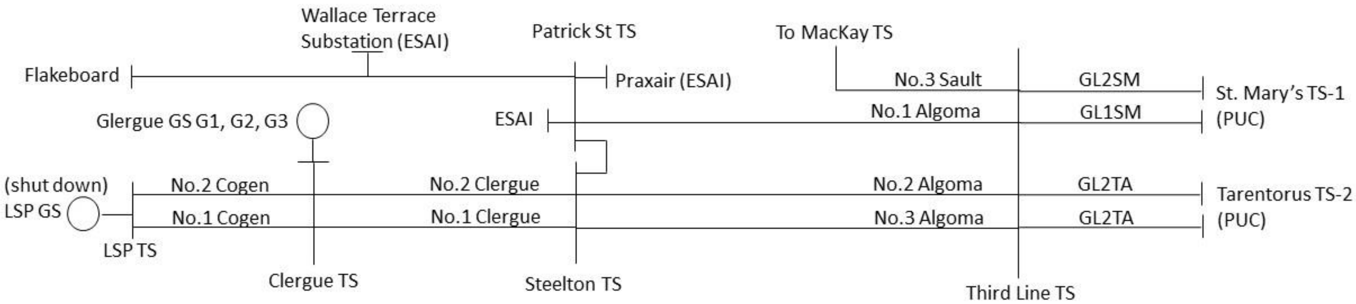
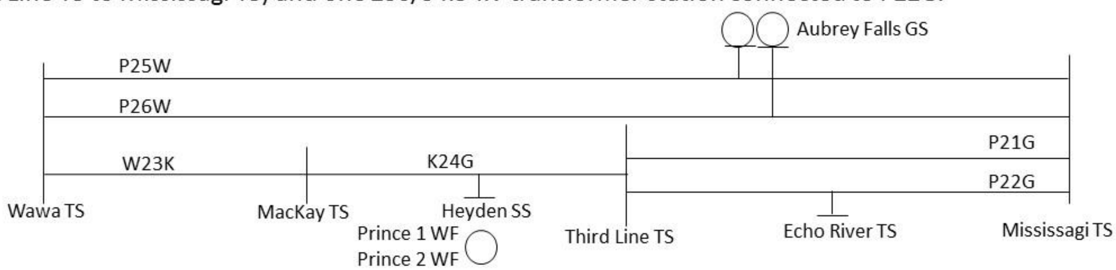


Figure 2d – GLPT and Hydro One 230 kV Eastern Area – Hydro One 230 kV lines P25W and P26W from Wawa TS to Mississagi TS, GLPT 230 kV lines W23K (Wawa TS to MacKay TS), K24G (MacKay TS to Third Line TS), P21G and P22G (Third Line TS to Mississagi TS) and one 230/34.5 kV transformer station connected to P22G.



4. INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to GLPT:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- GLPT provided transformer, station and line ratings
- Hydro One provided Wawa TS autotransformer ratings
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1. LOAD FORECAST

As per the data provided by the LDCs, the load in the ELS-Region is expected to grow at a rate varying from -0.1% to 2.5% plus some larger customer load increases.

Table 2: Annual Load Growth for ELS-Region

LDC	Approximate % Growth Rate 2013 to 2018	Approximate % Growth Rate 2019 to 2023
PUC	Slightly Negative	Slightly Negative
API	0.0 to 2.5%	0.0 to 2.5%
CPUC	0%	0%

Large Industrial Customer Load Increases	Approximate MW Increase 2013 to 2018	Approximate MW Increase 2019 to 2023
Sault Ste. Marie Southern Area	19.4	3.2
Wawa TS/Anjigami TS Northern Area	20.85	0

The Needs Assessment considered gross loads at individual stations based on the 2013 summer or winter peak non-coincident load and the peak summer or winter load forecast for stations within the Region. The station load forecast was developed by using data provided by the LDC’s load forecasts and other customer load forecasts.

5. ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Assessment:

1. The Region is winter peaking, but this assessment includes both summer and winter peak loads where one is more critical than the other due to equipment ratings.

2. Forecast loads are provided by the LDCs and other customers.

3. Stations having negative load growth over the study period are assumed to have steady load.

4. In developing a worst-case scenario, DG and CDM contributions were not considered.

5. Review and assess impact of any on-going or planned development project in the ELS-Region during the study period.

6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables and stations.

7. Station capacity adequacy is assessed assuming a 90% lagging power factor on the HV and non-coincident station loads.

8. Transmission line adequacy to be assessed using non-coincident peak station loads in the region.

9. The needs were first identified by looking at the total normal supply capacity (TNSC) of the elements that supply a specific LDC or other customer compared to the three month average peak over the last 5 years and the peak load over the last five years. This was used to identify any planning issues based on the existing peak loads. The 2023 peak load was then compared to the TNSC and if peak loads were greater than 75% of the TNSC for specific station/line(s), these station/line(s) were identified for further study. The TNSC takes into consideration one element out of service where load is not supplied via a single line/station.

10. Transmission adequacy assessment is primarily based on:

    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their continuous ratings and transformers within their summer 10-Day limited time ratings (LTR) if there are two transformers and 10 day LTR's exist.
    - All voltages and voltage declines must be within pre- and post-contingency ranges as per ORTAC criteria.

11. The ELS-Region has a considerable amount of hydro generation connected to the 115 kV system and wind generation connected to the 230 k system. Two new wind farms are in the process of connecting to the Gartshore 115 kV lines (58.3 MW) and K24G 230 kV lines (25.3 MW). Both have had recent detailed IESO System Impact Assessments (SIA) and GLPT Customer Impact Assessments (CIA) completed which did not identify concern in the area regarding overload of facilities. Generation in the area is generally more critical to line overload than LDC and other customer load. These studies were reviewed as part of this Needs Assessment process.

12. For the Sault Ste. Marie Southern section of the ELS-Region, the 98% dependability of generation from Clergue GS was used in this assessment. Glergue GS dependable generation was assumed to be 10 MW. This is based on an IESO Feasibility Study (Confidential) undertaken to assess the Algoma lines for adequate capacity.

This Needs Assessment was conducted to identify emerging needs and determine whether or not further coordinated regional planning should be undertaken for the Region or electrical areas. It is expected that further studies in the subsequent regional planning process will undertake detailed analysis and also assess ORTAC performance requirements.

6. RESULTS

6.1. Transmission Capacity Needs

6.1.1. 230kV Connection Facilities

Based on the demand forecast, there is sufficient capacity throughout the study period at Echo River TS which is a 230kV connected load station. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

East-West Tie lines are to be upgraded in 2019. Hydro One's CIA entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customers in the area. The Hydro One CIA assessed the Short-Circuit Impact, Voltage Impact and Supply Reliability Impact.

6.1.2. 230/115kV Autotransformers

No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

6.1.3. 115kV Connection Facilities

Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the demand forecast from one of the other customer in Sault Ste. Marie projecting an increase in peak load. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

6.2. System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

There is a concern about transformer failure in the region where there are many load stations with just one transformer supplying customer load. The ORTAC restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

6.3. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)
- Tarentorus TS (equipment & relaying)

6.4. Other Considerations

Restoration of most of the GLPT transmission system can be accomplished from a black start procedure which energizes the Sault Ste. Marie Southern Area load/generation and eventually up to MacKay TS South Central Area to load/generation and run as an island. It is expected that for the loss of Wawa TS T1 and T2 transformers and by configuration the Wawa TS/Anjigami TS Northern Area, the delay in restoration of GLPT connected load/generation can be greater than the ORTAC standard of 8 hours. There is a need to study if this area could be operated as an island until the supply from Hydro One Wawa TS can be restored.

7. RECOMMENDATIONS

The study Team Recommends:

7.1. The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

7.2. The potential needs identified for the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS does not require further regional coordination. The study team recommends that a “localized” wire only solution be developed by GLPT and the impacted customer.

7.3. The potential need identified for the restoration of load after a single supply transformer failure which could violate the ORTAC criteria of restoring load within 8 hours does not require further regional coordination. The study team recommends that GLPT and the impacted distributor continue to work on this need.

8. NEXT STEPS

Following the Needs Assessment process, the next regional planning step, based on the results of this report, are:

8.1. GLPT and the relevant LDC’s are to further assess and/or develop local wires solution as identified in the needs outlined in Section 7.1 and 7.3.

8.2. GLPT and the relevant customers will further assess and/or develop local wires solution as identified in the needs outlined in Section 7.2.

9. REFERENCES

Planning Process Working Group (PPWG) Report to the Board

IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

IESO Feasibility Study (Confidential) for Algoma Lines Redevelopment

IESO System Impact Assessment (SIA) Report and Addendum Report for Bow Lake Wind Farm (CAA ID#: 2010-392)

IESO System Impact Assessment Report and Addendum Report for Goulais Wind Farm (CAA ID#: 2010-397)

GLPT Customer Impact Assessment (CIA) Report for RTK Canada, ULC (Rentech) increased 44 kV load dated April 23, 2014.

Customer Impact Assessment (CIA) Report for Hydro One New East-West Tie Project dated October 29, 2014.

10. KEY TERMS AND DEFINITIONS

Key terms and definitions associated with this Needs Assessment are cited here.

Normal Supply Capacity (NSC): The maximum loading that electrical equipment may be subjected to continuously under nominal ambient conditions such that no accelerated loss of equipment life would be expected.
Coincident Peak Load: The electricity demand at individual facilities at the same specific point in time when the total demand of the region or system is at its maximum.

Contingency: The prevalence of abnormal conditions such that elements of the power system are not available.

Conservation and Demand Management (CDM): Programs aimed at using more of one type of energy efficiently to replace an inefficient use of another to reduce overall energy use, and influencing the amount or timing of customers' use of electricity.

Distributed Generation (DG): Electric power generation equipment that supplies energy to nearby customers with generation capacity typically ranging from a few kW to 25 MW.

Gross Load: Amount of electricity that must be generated to meet all customers' needs as well as delivery losses, not considering any generation initiatives such as CDM and DG. It is usually expressed in MW or MVA.

Limited Time Rating (LTR): A higher than nameplate rating that a transformer can tolerate for a short period of time

Load Forecast: Prediction of the load or demand customers will make on the electricity system

Net Load: Net of generation (e.g. CDM and DG) deducted from the Gross load

Non-Coincident Peak Load: The maximum electricity demand at an individual facility. Unlike the coincident peak, non-coincident peaks may occur at different times for different facilities.

Peak Load: The maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.

Total Normal Supply Capacity (TNSC): The maximum loading that electrical equipment may be subjected to post contingency (n-1) under nominal ambient conditions such that an acceptable accelerated loss of equipment life would be expected. For a single element supply system the TNSC equals the NSC.

11. ACRONYMS

CDM Conservation and Demand Management

CIA Customer Impact Assessment

DG Distributed Generation

DSC Distribution System Code

IESO Independent Electricity System Operator

IRRP Integrated Regional Resource Planning

kV Kilovolt

LDC Local Distribution Company

LTR Limited Time Rating

LV Low-voltage

MVA Mega Volt-Ampere

MW Megawatt

NA Needs Assessment

NSC Normal Supply Capacity

OEB Ontario Energy Board

OPA Ontario Power Authority

ORTAC Ontario Resource and Transmission Assessment Criteria

PF Power Factor

PPWG Planning Process Working Group

RIP Regional Infrastructure Planning

SIA System Impact Assessment

SS Switching Station

TNSC Total Normal Supply Capacity

TS Transformer Station

TSC Transmission System Code

Great Lakes Power Transmission

Report for:

Replacement of Protection Relays Study

GLPT Transmission System

Sault Ste. Marie

OLE Project No. 10-003
Revision A

OneLine Engineering Inc. – Electrical Power Specialists

Form: F730-06-R0
Form Date: 28 October 2008

TABLE OF CONTENTS

APPENDICES

1.0 EXECUTIVE SUMMARY

Great Lakes Power Transmission (GLPT) system has experienced a number of failures of protective relays during the recent past years. GLPT contracted OneLine Engineering Inc. (OLE) to conduct a comprehensive study for replacement of all the existing relays in the GLPT system.

This report presents data collection of all the existing relays, historical failure rates, estimated life expectancy, determination of degree of obsolescence and development of a comprehensive relays replacement program with budgetary costs and time schedules.

The objective of the study is to contribute towards evolution of the GLPT transmission stations into Smart Grids and achieve the desired integrated protection of all the stations as well as the Critical Infrastructure and Critical Cyber Assets that control or affect the reliability of North America's bulk electricity systems.

It is worthy to mention that the Relays Replacement Program will reduce the inventory of relays from 37 types to 18 types.

Whereas, total Budgetary Cost (**Purchase Price**) of the new proposed relays would be **US$ 1,777,174** (**Appendix-C**). The purchase price does not include expenses to implement the project.

Recommendations and Conclusions:

The recommendation and conclusions drawn from the Study for Replacement of Protection Relays are as follows. This report recommends that:

1. GE relays be adopted as 'A' Protection and SEL Relays as 'B' Protection in accordance with the new applicable standards such as NERC CIP Compliance and the Ontario Transmission System Code. Adoption of these relays will facilitate the adoption of Ethernet based IEC61850 communications in the future.

2. All K series relays (KCEG & KBCH) need be replaced with the recommended relays as early as possible. These relays (AREVA/ALSTOM) are predominately in service at Anjigami and Watson TS. The K series relays are also in service at Clergue, Hollingsworth, Mackay, Magpie and Third Line transmission stations. Reference **Appendix-A**.

3. Alstom P series relays (MiCOM relays) have some connectivity/communication issues with the existing RTUs and the other IEDs (Intelligent Electronic Devices) such as protective relays. At present, the GLPT transmission system incorporates 77 MiCOM series relays in total. It is recommended that the MiCOM relays should be replaced at an earlier stage rather than waiting for the end of their life expectancy. The suitable time schedule for the relays replacement will be re-scheduled by the GLPT protection and control group.

4. All obsolete, electro-mechanical and static protective relays should be replaced with modern digital relays as soon as possible.

5. In view of feedback from the Manufacturers and natural aging/deterioration of digital relays, a safe service period of 'twenty years' has been determined to estimate budgetary cost and develop a relay replacement program. Reference **Appendix-G.**

6. Rapid development in relaying technology may also have a great impact on the existing relays in the future. The relays may be replaced at an earlier stage where they appear to be replaced in the replacement program later than five to ten years or more.

7. At present, most of the 115kV breakers have stand-alone breaker failure relays in addition to their 'A' and 'B' protection. Since the breaker failure function will be integrated with the main protective relays, the breaker failure relay will be eliminated for all 115kV feeders wherever it would be possible. This recommendation is good for all GLPT stations except Third Line TS, where stand-alone two relays type GE/C60 will provide breaker failure function for 115kV breakers of power transformers T1 and T2 in the forth-coming 115kV 1½ breaker scheme project. However, breaker function will be incorporated in the protective relays of the respective feeders in the new 115kV 1½ breaker scheme project.

8. For increased reliability and safe operation of the system, the required switchgears and related equipment/relays should be installed as described under Improvement in Protection and Control Schemes-Article 4.6.

2.0 GENERAL

2.1 Introduction

It is known that protective relays are crucial for safe and reliable operation of transmission systems. Fast response, high selectivity and secure communication of relays prevent indiscriminate outages and blackouts.

Based on the collected relay data and condition assessment, this report concludes that many of the existing relays in the GLPT system need to be replaced urgently because either they are obsolete, electro-mechanical, static or they are at the end of their life cycle. Replacement of these relays by modern programmable digital relays will provide the desired functions, reduced operational costs and increased cyber security.

This report recommends that replacement of the associated Remote Terminal Units (RTUs) and installation of Firewalls at the GLPT transmission stations be carried out together with the relays replacement program.

2.2 NERC CIP Compliance

North American Electric Reliability Corporation (NERC) requires the utilities in the region to comply with the reliability standards that is one of the NERC's requirements. Among these are the Critical Infrastructure Protection (CIP) Cyber Security Standards.

The new GE and SEL relays will provide the following desired protection and control functionality – *Access Control, Intrusion Detection and Auditing & Reporting*. Following is a brief description of these functions:

Access Control: Access Control function provides secure multi-level permissions and multi-factor supervisory controls. It provides discrete authentication for settings and commands as per authorization of the individuals and control factor that can lock or unlock a protective device for configuration changes and any other modifications.

Intrusion Detection: Intrusion Detection function provides ability to detect potential breaches. Any unsuccessful attempts are logged and alarmed.

Auditing & Reporting. Auditing & Reporting function is an important part of a secure and reliable system. It provides information on Event Logging such as relay configuration changes. The reports of 'Setting Security' include complete information on dates and times of relay setting changes,

user's address, list of modifications and details how the setting changes were made such as Keyboard, Ethernet or Front serial port of the relay.

The GLPT transmission system has five Critical Assets at present. Following is a list of the same:

List of Existing GLPT Critical Assets:

1. Third Line TS
2. Mackay TS
3. GLPT System Control
4. GLPT Back-up Control Centre – Andrews
5. GLPT Back-up Control Centre – Wawa

The number of GLPT Critical Assets may increase in the future as the system would expand with growth of industrial, commercial and domestic loads as well as changing requirements within NERC-CIP.

2.3 IEC61850 Standard and GOOSE

The selected GE and SEL relays support IEC61850 communication schemes and other communication buses. The standard describes the communication between IED's and a Scada system including various tasks inside a substation. The standard is meant for fast transfer of events, data storage and communication protocol requirements.

Moreover, a GOOSE (Generic Object Oriented Substation Event) message, as a part of IEC 61850 standard, is used to exchange data between IED's (such as protective relays) in a substation. GOOSE facilitates fast and reliable transferring of event data over an entire substation network. The substation events include commands, alarms, indications and messages. GOOSE is also used for tripping of switchgear, starting of disturbance recorder and providing position indication for interlocking.

The IEC61850 standard is gaining popularity in North American utilities. Adoption of IEC61850 communication standard in future would give great benefits.

The communication standard information is a part of the ordering data for GE and SEL relays.

2.4 Inventory of Existing Relays

At present, the GLPT transmission system is protected by 37 types of relays manufactured by ABB, AREVA, Alstom, Basler, Canadian General Electric, General Electric (GE), SEL and Westinghouse.

The existing 232 protective relays (auxiliary relays not included) vary from distance, line differential, overcurrent, directional overcurrent to bus and transformer differential protection. The Inventory of Existing Relays **Appendix-A** contains comprehensive information regarding the type, function and number of each relay in each GLPT transmission station. Following are the brief details:

ABB Relays (CO-11) 4

Alstom MiCOM Relays (P series) 77

Areva Relays (KCEG, KBCH, MFAC, MCAG)....................... 45

Basler Relay (BEI-25A) 1

Canadian GE Relays (MCTI, IJS, IAC) 5

GE Relays (Micro-processor based)...................................... 12

SEL Relays (Micro-processor based) 88

Westinghouse Relays 2

Total Protective Relays-- 232

Electro-mechanical relays:	***23*** *electro-mechanical relays.*
Static relays:	***9*** *static relays.*
Digital/Numerical relays:	***200*** *digital/numerical relays*
Obsolete relays:	***24*** *obsolete relays*

2.5 General Data of Relays: Nameplates Info Plus

The **Appendix-F** presents complete information about the type, make, serial number, part number, year of manufacture, year of installation, availability of spares and condition of each relay in the GLPT system. This information was collected by site visits. Also, the respective manufacturers were contacted for obtaining the related information.

2.6 Life Expectancy of Protective Relays

The respective Manufacturers were contacted for Life Expectancy of their relays. Copies of correspondence with the Manufacturers are attached as **Appendix-G**. The following table shows the life expectancy given by the Manufacturers:

Manufacturer	ABB	Alstom	Areva	Basler	GE	SEL	Westing-house
Life Expectancy (Years)	20	20-25	20-25	25	25	25*	No feedback

*SEL informed that Life Expectancy of their digital relays is over 25 years with power supply replacement.

Also, information about lifespan of digital, electro-mechanical and static relays was also widely searched on internet. The collected information indicates their lifespan as follows:

Digital Relays: 15-20 years

Electro-mechanical Relays: 35-40 years

Static Relays: Up to 30 years (capacitors used in the relays may have lifespan of 7-10 years)

2.7 Availability of Spare Relays

OneLine Engineering contacted the following Manufacturers for the information on availability of the spare relays. Based on their feedback, following are the details:

ABB Relays .... 6 - 8 Weeks

Alstom MiCOM Relays .... 1 - 2 Business Days

Alstom/Areva MIDOS Series* Relays .... 6 - 8 Weeks

Basler Relay .... 2 Weeks

General Electric Relays .... 20 Business Days

SEL Relays .... 3 - 4 Weeks

Westinghouse Relays .... No feedback

* MIDOS series relays include tripping and supervision relays type MVAJ and MVAX.

2.8 Time to Repair Relays

The following information was collected from the Manufacturers:

ABB Relays:	2 Weeks
AREVA/Alstom Relays:	2 Weeks
Basler Relays:	2 Weeks
GE Relays:	20-30 Business Days
SEL Relays:	3 Business Day plus Shipping
Westinghouse Relays:	No feedback

3. METHODOLOGY

3.1 Overall Review of the GLPT Relays

An overall review of all the existing GLPT system relays indicates that the protective relays range from digital programmable to static and electromechanical relays.

The GLPT system has 200 digital, 9 static and 23 electro-mechanical relays. Out of these relays, 24 relays are obsolete. The details will follow.

At present, the 230kV and 115kV transmission systems mostly utilize MiCOM series relays as 'A' protection and SEL relays as 'B' protection.

Following are the locations where 'obsolete, electro-mechanical and static' relay are still in service at present:

A. Obsolete relays: 24 obsolete relays are in service at the following stations:

Anjigami TS: All 115kV Feeders

Hollingsworth TS: 115kV Hollingsworth Line

Magpie TS: 115kV High Falls Line

Third Line TS: i) 115kV Northern Avenue Line
ii) 115kV Sault No. 3 Line
iii) 115kV GL1 SM Line
iv) 115kV GL2 SM Line
v) 115kV GL1TA Line
vi) 115kV GL2TA Line

Watson TS: i) 115kV High Falls Line 1 & 2
ii) 34.5kV McPhail No.2
iii) 34.5kV Wawa no.2
iv) 34.5kV bus No. 1 & 2

AREVA/Alstom informed that the KCEG 140 series relays and LFZP131 series relays (OPTIMHO) are obsolete now. Reference **Appendix-G**.

,

B. Electro-mechanical relays: 23 Electro-mechanical relays still exist in Anjigami, Clergue, Hollingsworth, Hwy. 101, MacKay, Steelton, Third Line and Watson transmission stations. Their details are given below:

Anjigami TS: 115kV Bus differential protection

Clergue TS: 12kV Bus tie and station service transformers

Hollingsworth TS: 11.5kV Bus differential protection

Hwy. 101 TS: 44kV Limer Line

MacKayTS: 230kV Bus T2H differential protection

Steelton TS: 115kV Bus differential protection

Third Line TS: i) 230kV Bus T1H and T2H differential protection
ii) 115kV North and South bus differential protection

C. Static relays: 9 static relays are in service at present. Their details are given below:

Clergue TS: 115kV Cogen Lines No. 1 & 2 (Breaker Failure)

Third Line TS: i) 115kV Northern Avenue Line
ii) 115kV Sault No. 3 Line
iii) 115kV GL1 SM Line
iv) 115kV GL2 SM Line
v) 115kV GL1TA Line
vi) 115kV GL2TA Line

Watson TS: 34.5kV Synchronizer

3.2 History of Relays Failure and Replacement

There have been a number of relay failures mainly at Anjigami, Magpie and Watson TS. The AREVA relays of KCEG series have malfunctioned or failed. Complete details are not available. However, the available information is included in this report.

The study of the History of Relays Failures showed that the troubles appeared in those relays that had been in service for more than ten years or were at the end of their life cycle. As a historical record, following are the details when the old relays were replaced by MiCOM or SEL relays a few years ago:

Anjigami TS – 'A' Protection of 115kV High Falls Line # 1 & 2 and Hollingsworth Line were replaced by MiCOM P441 in the year 2002.

Clergue TS – 'A' and 'B' Protection of 115kV Clergue Line # 1 & 2 were replaced by SEL and MiCOM relays in the year 2008.

Gartshore TS – 'A' and 'B' Protection of all 115kV lines were replaced in the year 2006.

Hollingsworth TS – 'A' and 'B' Protection of all 115kV feeders were replaced in the year 2005.

Mackay TS – 'A' and 'B' Protection of 230kV feeders were replaced in the year 2006.

'A' and 'B' Protection of all 115kV feeders were replaced in the year 2008.

Magpie TS – 'A' and 'B' Protection of all 115kV feeders were replaced in the year 2008.

Northern Av. TS – 'A' and 'B' Protection of all 115kV feeders were replaced in the year 2004.

Steelton TS – 'A' and 'B' Protection of all 115kV feeders were replaced in the year 2004 and the corresponding breaker failure relays were replaced in the years 2006 and 2007.

Third Line TS – 'A' and 'B' Protection of all 230kV feeders were replaced in the year 2005.

‘A’ and ‘B’ Protection of all 115kV feeders were replaced in the year 2000, 2002, 2004 and 2007.

Watson TS – ‘A’ and ‘B’ Protection of 34.5kV Dunford No. 1 & 2 were replaced in the year 2002. ‘A’ and ‘B’ Protection of 34.5kV Wawa No. 1, Scott No.1 and 2 feeders were replaced in the year 2010.

Three KCEG relays have failed during the last three years at Watson TS. Reference **Appendix-F**.

3.3 Forced Outages from 2004 to Present

Reviewed Forced Outages from the year 2004 to present to check performance of the protective relays. Following are results of the review:

Year of Outages	Forced Outage Incidents	Discriminate Outages†	Indiscriminate Outages∆	Relays Malfunction*
2004	17	13	2	2
2005	37	35	0	2
2006	26	24	1	1
2007	40	40	0	0
2008	57	57	0	0
2009	32	32	0	0
2010	20	20	0	0
2011	2	2	0	0

† Discriminate Outages: Discriminate Outages relate to the trippings where the protective relays operated ‘correctly’ to the type of fault and its location and the relay settings.

∆ **Indiscriminate Outages:** Indiscriminate Outages relate to the trippings where the protective relays operated ‘incorrectly’ to the type of fault and its location and the relay settings.

*** Relays Malfunction:** Relays Malfunction relates to the trippings where the protective relays operated due to the causes other than any fault conditions. For example: in year 2004, two outages occurred due to cold temperature below -25C° in the relay room and forgotten short-circuited CTs.

Isokeraunic level of Sault S. Marie: Isokeraunic Level is defined as the number of days in the year on which thunder is heard.

If Isokeraunic Level is higher than 30 days, the area is considered as high lightning area. It is estimated that the isokeraunic level of Sault Ste. Marie, Montreal River and Wawa areas is more than 30 days.

Recommendations to Minimize Outages by Lightning Strokes: It has been observed from the records of Forced Outages that most of the outages were caused by direct or indirect lightning strokes. The outages by lightning strokes can be minimized by reducing the tower footing resistance in the entire GLPT transmission system. A typical value for a good tower footing resistance is < 1.0 ohms. This would improve the degree of shielding by the overhead ground conductors against lightning.

The reduction in tower footing resistance will also reduce the number of surges reaching power transformers, lightning arresters and other station equipment like Wave Traps, CTs and VTs. Over-voltage surges affect the equipment service life.

3.4 Review of 230kV and 115kV Switchgears

Opening Time of circuit breakers also greatly affects the total tripping time. Therefore, test results of 115kV circuit breakers were reviewed to assess any such deficiency that might affect the system operation and reliability. 230kV breakers have never been tested for opening/closing times since they were commissioned.

The available test results of 115kV breakers were reviewed for the opening/closing times. All the results show the measured opening/closing times within permissible limits: Opening < 40 m Sec. and Closing < 90 m Sec.

3.5 Review of Existing Relay Schemes

The existing protection schemes were reviewed and found the following deficiencies in each transmission station:

Anjigami TS:

i) **115kV Feeders:** All 115kV feeders do not have adequate protection. The feeders are protected by directional overcurrent relays.

ii) **115kV Bus:** 115kV bus has no ‘B’ Protection.

iii) **44kV Limer Line:** 44kV Limer Line has no circuit breaker and the required protective relays.

iv) **Transfer Trip from Relay 86T:** In case of a fault on 44kV Limer Line, relay 86T of transformer T1 sends a transfer trip signal to Hwy. 101 TS that causes unnecessary outage to the customers fed from Hwy. 101 TS. The scheme needs to be revised accordingly.

Clergue TS:

i) **115kV Cogen Lines No. 1 & 2:** The 115kV Cogen Lines No. 1 & 2 (underground cables) are protected by relays type KCEG 112. This type of relay operates by picking up of a single Earth Fault element that protects the cables only against ground faults. There is no 'B' protection on both lines.

ii) **Main Power Transformers MT1 & MT2:** 'A' and 'B' Protection of main transformers MT1 and MT2 are connected in series to the same CTs.

Gartshore TS:

115kV Ring Bus: Gartshore TS has 115kV Ring Bus in the GLPT system. Like other transmission stations, it does not require bus differential protection. This benefit arises because faults on the bus structure of the ring are detected by the branch protection since all the part of the ring bus itself lie within a branch protection zone.

Hollingsworth TS:

i) **Power Transformer T1:** 'A' and 'B' Protection of 115kV Hollingsworth Line are only overcurrent relays. There is no circuit breaker on 115kV side of transformer T1. It has an Air Break Switch.

ii) **11.5kV Station Transformer:** 11.5kV station transformer is located within the bus zone. Switching of the station transformer sometimes causes the bus differential relay (MFAC) to actuate and results in tripping of the associated circuit breakers of the bus zone (CB # 991, 993 & 999). This unwanted tripping may be prevented by a time delay in the trip circuit. The new bus differential relay SEL-587Z has a time delay facility. Enabling the built-in time delay in the relay would avoid the indiscriminate tripping.

Hwy. 101 TS:

i) **44kV Limer Line:** Hwy. 101 TS is a part of 44kV sub-transmission system. The 44kV Limer line to Hollingsworth TS is protected by electro-mechanical relays (ABB: CO-11). The existing protection needs to be upgraded.

44kV Limer Line to Anjigami TS has only Motor Operated Switch (#1042). Any fault on 44kV Hollingsworth or Anjigami line will isolate the complete station and send transfer trip signal to the opposite ends.

Magpie TS:

i) **115kV Lines:** 'A' and 'B' Protection of all 115kV lines at Magpie TS are connected in series to the same set of CTs.

'B' Protection of all 115kV High Falls line is 'directional overcurrent relay'.

ii) **115kV Ring Bus:** Magpie transmission station has 115kV Ring Bus in the GLPT system. Like other transmission stations, it does not require bus differential protection. This benefit arises because faults on the bus structure of the ring are detected by the branch protection since all the parts of the ring bus itself lie within a branch protection zone.

Mackay TS:

230kV bus differential protection relays are Electro-mechanical and need to be replaced as soon as possible.

Northern Av. TS:

i) **Power Transformer T1:** The differential and overcurrent relays of 115kV/34.5kV power transformer T1 are connected in series to the same CTs. Also the differential zone needs to be redefined for the power transformer.

ii) **115kV Breaker for Transformer T1:** The high side of power transformer T1 has no circuit breaker. The 115kV line faults are cleared by the 34.5kV breaker. This results in unnecessary switching of power transformer T1.

Steelton TS:

115kV Ring Bus: Steelton TS has two back-to-back 115kV ring buses. The 115kV line protection zones do not overlap the 115kV bus zones, therefore do not protect both buses.

The existing electro-mechanical relays of 115kV buses do not provide full protection for all phases. Also 'B' Protection for both buses is not provided.

Third Line TS:
230kV and 115kV bus protections are electro-mechanical relays.

Six 115kV feeders are protected by obsolete relays. List of these feeders is given under Article 4.1.

Watson TS:

i) **115kV High Falls Line 1 & 2:** 115kV High Falls Line 1 & 2 do not have adequate protection. The existing CTs are suitable for provision of 'A' and 'B' Protection. However, 115kV PTs would be required on both lines for the proposed distance relays. The feeders are protected by directional overcurrent relays at present.

ii) **115kV High Falls Line # 2:** 115kV High Falls Line # 2 has no circuit breaker. The high side of power transformer T2 needs be upgraded by providing a circuit breaker and the proposed protective relays.

iii) **Line PTs for 34.5kV Feeders:** Line PTs for all 34.5kV feeders are required to be installed.

iv) **Transfer Trip Scheme:** Transfer Trip Scheme of 115kV lines needs to be reviewed and corrected.

3.6 Improvements in Protection and Control Schemes

'Two Heads Are Better Than One' option has been adopted for providing 'B' Protection as well as 'A' Protection where 'B' Protection was non-existent in 115kV transmission and 44kV sub-transmission systems. This is in accordance with the Ontario Transmission Code.

Low Impedance Bus Differential Protection: The existing 230kV and 115kV bus protective schemes utilize High Impedance Differential relays (KBCH, MFAC). Instead of these relays, Low Impedance Differential relays are proposed. These relays have a few benefits over the high impedance differential relays such as individuality of each current is not lost and high security against CT saturation.

Sub-Cycle Distance Protection: Sub-cycle distance protection is proposed for 230kV lines. GE/D90plus and SEL-421 relays will provide system stability. The relay characteristics will allow increased line loading.

Distance Relays for 115kV Lines: For all 115kV lines, distance relays have been proposed as ‘A’ and ‘B’ Protection.

Following are proposed improvements in protection and control schemes of the GLPT transmission stations:

Anjigami TS:

i) **115kV Feeders:** Distance relays are proposed for ‘A’ and ‘B’ Protections of all 115kV feeders at Anjigami TS. Reference **Appendix-D**.

ii) **115kV Bus:** The 115kV bus at Anjigami TS has only one protective relay (High Impedance Differential relay type MFAC). The ‘B’ Protection for the bus does not exist. In order to increase reliability of the system, low impedance bus differential relay type B30 (GE) is proposed as ‘A’ Protection and high impedance relay type SEL-587Z as ‘B’ Protection.

In order to separate ‘A’ and ‘B’ Protection of 115kV bus, new separate CTs with circuit breaker # 844 are required.

iii) **Power Transformer T1 and 44kV Limer Line:** Low side of power transformer T1 has no circuit breaker and no protective relays for 44kV Limer Line. During a fault on Limer Line, a transfer trip signal from Hwy. 101 trips the 115kV breaker #864 at Anjigami TS. This results in unnecessary switching of the power transformer to clear a line fault. Provision of 44kV circuit breaker and protective relays for Limer Line will prevent the unnecessary switching.

It is worthy to mention that the insulation of power transformers is degraded by switching surge due to each switching operation. This reduces the service life of power transformers.

Clergue TS:

115kV Cogen Lines No. 1 & 2: The existing ‘single element’ Earth Fault relays type MiCOM P122 should be replaced for adequate protection of the lines.

115kV Cogen Lines No. 1 & 2 have very short length (less than 500 meters). Therefore, distance relays wouldn't be able to do their function accurately for such short lines. The proposed relays are high speed Directional Overcurrent relays type G/F60 and SEL-451-5 that will provide full protection for overcurrent, earth fault and breaker failure function.

The proposed 'B' Protection for the above lines shall utilize the existing CTs that are used for breaker failure relay (MCTI).

Main Power Transformers MT1 & MT2: 'A' and 'B' Protection should be connected to different set of CTs. Additional 115kV CTs (Ratio: 300/5) should be provided to separate both protections.

Hollingsworth TS:

i) **Power Transformer T1:** The existing 115kV Air Break Switch (AB) of power transformer T1 should be replaced by a circuit breaker. Provision of 115kV circuit breaker will help to avoid unnecessary switching off the power transformer due to a fault on the 115kV Hollingsworth line.

ii) **11.5kV Station Transformer:** 11.5kV station transformer is located within the bus zone. Inrush currents due to switching of the transformer sometimes cause the bus differential relay (MFAC) to actuate and result in tripping of the associated circuit breakers of the bus zone (CB # 991, 993 & 999). This can be avoided by introducing a time delay of approximately 50 milliseconds in the trip circuit. The new bus differential relay SEL-587Z has time delay facility. Enabling the built-in time delay in the relay would prevent the indiscriminate tripping.

Hwy. 101 TS:

i) **44kV Limer Line:** The existing electro-mechanical relays need to be replaced by the proposed relays for 'A' and 'B' Protection. Since 44kV Lime Line is a sub-transmission system, the line should have 'A' and 'B' Protection.

The existing Motor Operated Switch No. 1042 for the line section toward Anjigami TS should be replaced by a circuit breaker and the associated protective relays. In order to separate 'A' and 'B' Protection, installation of a set of additional 44kV CTs would be required.

Northern Av. TS:

i) **Power Transformer T1:** 'A' and 'B' Protection of power transformer T1 should be connected to different CTs. Separate 115kV and 34.5kV CTs need to be installed for proper differential protection zone of the transformer.

Provision of 115kV circuit breaker will help to avoid unnecessary switching off the power transformer due to a fault on the 115kV line.

Magpie TS:

i) **115kV Lines:** 'A' and 'B' Protection should be connected to different set of CTs. The Magpie station already has the required CTs for this purpose. Therefore, additional CTs will not be required.

Directional overcurrent relays ('B' Protection) of all 115kV lines should be replaced by the proposed distance relays.

Mackay TS:

There are no other specific issues with protective relays except those mentioned earlier under Article 1.0 (Recommendations and Conclusions).

Steelton TS:

i) **115kV Ring Bus:** The existing electro-mechanical relays of 115kV bus 1 & 2 should be replaced with the proposed digital relays. The existing bus protection does not provide full protection of all phases. Also 'B' Protection for both buses is not provided.

Moreover, bus differential protection for both buses is required for this station because the protection zone of 115kV lines do not overlap the 115kV buses zone. This is due to the reason that the station has stand-alone CTs and breaker bushing CTs.

ii) Breaker failure relay for 115kV breaker # 232 will be required for this station. The proposed relay SEL-451-5 has built-in breaker failure function and Ethernet communication port.

Third Line TS:

Same remarks as mentioned above under Mackay TS.

Watson TS:

i) **Incorporation of IEC 61850 standard:** Ethernet based communication architecture scheme, as per IEC 61850 standard, will be implemented in Watson TS on trial basis.

i) **115kV High Falls Line 1 & 2:** For distance protection of 115kV High Falls Line 1 & 2, the existing CTs are adequate for provision of 'A' and 'B' Protection. However, separate 115kV line PTs are required for both lines.

Watson TS has no 115kV bus; therefore, bus protection is not required.

3.7 Criteria for Relays Replacement

Anjigami TS and Wason TS have been placed on priority in the relays replacement program. These stations had many failures of protective relays during past three years. The failures occurred in the Areva KCEG series relays. Both stations utilize the highest number of obsolete KCEG series relays in the GLPT system.

Replacement of KCEG 140 relays at Hollingsworth and Magpie TS has also been placed on priority. Reference **Appendix-B**.
All existing relays of 115kV lines at Third Line TS will be replaced in the year 2011. New 115kV yard will be rebuilt to 1½ breaker scheme.

The rest of the Relays Replacement Plan and Schedule has been developed according to the end of lifespan of relays in the GLPT system.

3.8 Technical Evaluation of New Relays

Arc Flash Detection Feature: The proposed overcurrent relay SEL-751A has added functionality that was non-existent in the previous versions of SEL overcurrent relays such as Arc Flash Detection. The Arc Flash functionality can be programmed in the relay to monitor its associated bay or metal-clad cubicle and as well as the other bays. Various functions are available in the relay to implement tripping upon detection of Arc Flash.

SEL overcurrent relay type SEL-751A with Arc Flash detection feature is proposed to replace the entire GLPT system overcurrent relays where directional feature is not required such as station transformers and medium voltage incoming breakers.

SEL-751A adapts system control based on 'pre-fault' condition.

Digital and Numerical relays: It is known that Numerical Relays are a natural development of Digital Relays. However, the digital and numerical relays both use micro-processor technology. The distinction between digital and numerical relays lies only in 'fine technical' details. Both terms are interchangeable.
SEL relays incorporate basically numerical relay technology. Although the digital/numerical relays perform multi-functions simultaneously such as distance protection, overcurrent protection, under-voltage, over-voltage, check Synchronism, CB condition monitoring and many more. The relays have many features in one piece of hardware. It looks like 'putting all eggs in one basket' but the newer generation of digital/numerical relays has been well designed in view of the past experience of static and older version of digital/numerical relays. The reliability and availability of the relays are dependable.

Ethernet Communication: GE and most of SEL relays have Ethernet Communication ports. However, the SEL relays that do not have Ethernet Communication port can be connected through SEL Ethernet Transceiver in order to obtain Ethernet Communication.

Moreover, Ethernet card option would provide two copper or fiber ports for failover redundancy.
D90plus Distance Relays are proposed for 230kV system. The relay has communication up to three independent IP addresses. The relay can have up to three Ethernet ports (Fiber and Copper).

DNP 3.0 Protocol: GE relays type B90, D90plus, D60, C70, F60 and L90 have communication option for DNP 3.0 and other communications standard protocols.

SEL relays type SEL-411L, SEL-421-5, SEL-451-5, SEL-487E, SEL-487V and SEL-751A have communication option for DNP 3.0 and other communications standard protocols.

SEL-587Z does not have communication protocol DNP 3.0. The relay may use Modbus, ASCII and binary protocols for communication with SCADA, local HMI or MODEM.

IEC61850 Standard: The GE and SEL relays have also option for the IEC-61850 communication standard. This standard is gaining the popularity amongst the North American utilities. This standard may be chosen as well as DNP 3.0 at the time of purchasing the protective relays. The associated GOOSE messaging would facilitate enhanced utilization of the available bandwidth for communications.

Mirrored Bits: SEL relays incorporate Mirrored Bits communication mode for increased data transmission speed if it is used for SEL relay-to-relay communications. However, it may not be effective when communicating amongst more than two devices. Mirrored Bits concept is not applicable to a multi-vendor system.

4.0 RELAYS REPLACEMENT PROGRAM

4.1 Replacement Plan and Schedules

The chart of Replacement Plan and Schedule shows the year when the existing relays will reach their end of lifespan. It gives complete details about obsolete, electromechanical, static and digital relays at each GLPT station. This plan would be helpful to re-schedule the replacement of relays. **Appendix-B.**

4.2 Proposed Relays: 'A' and 'B' Protection

Appendix-D gives complete details of Relays Replacement Program for each feeder in each station. The details include the feeder name, type of existing relays/ proposed relays, year and budgetary price. Also total budgetary cost of relays replacement for each station is given at the end.
At present, the following voltage levels exist in the GLPT system:

-- 230kV System
-- 115kV System
-- 44kV System
-- 34.5kV System
-- 12kV System

Following table shows listing of the proposed relays for the above voltage levels:

Type of Protection	230kV	115kV	44kV	34.5kV	12kV
Distance Protection	GE/D90plus SEL-421-5	GE/D60 SEL-421-5	-	-	-
Line Current Differential	-	GE/L90 SEL-411L	-	-	-
Directional Overcurrent	-	GE/F60 SEL-451-5	GE/F60 SEL-351S	GE/F60 SEL-351S	GE/F60
Overcurrent	-	-	-	SEL-751A	SEL-751A
Transformer Differential	GE/T60 SEL-487E	GE/T35 SEL-487E	-	-	-
Bus Differential	GE/B90 SEL-587Z	GE/B90 SEL-587Z	-	GE/MIB	SEL-587Z
Cap. Bank Protection	-	-	-	GE/C70 SEL-487V	-
Breaker Failure	SEL-451-5	GE/C60† SEL-451-5	-	-	-
Synchro-Check	-	-	-	GE/MLJ	GE/MLJ
Synchronizer	SEL-451-5	-	-	SEL-451-5	-
Load Shedding	-	GE/N60	-	-	-

† GE/C60 relay will be installed in Third Line TS for breaker failure function for power transformers T1 and T2. The reason is that there is no line protection on these feeders. The associated relays cannot sense which breaker had failed. Other feeders will incorporate breaker failure function from their respective protection at the station.

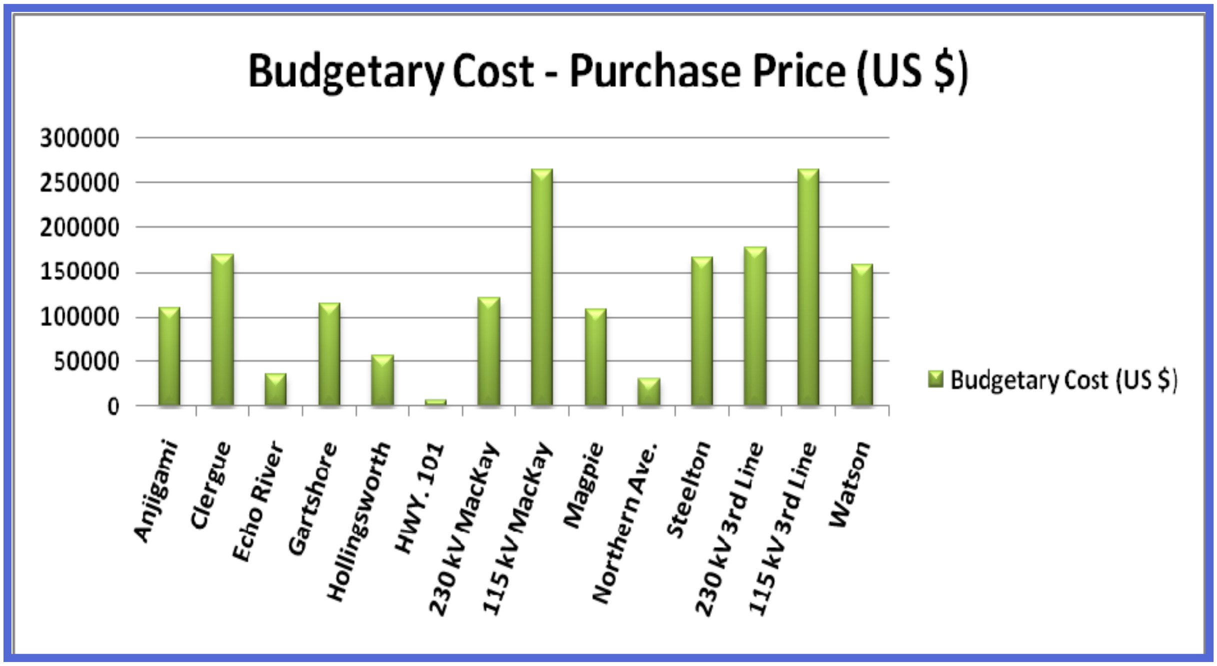
4.3 Budgetary Costs – Purchase Price

The table below indicates relays budgetary cost and year of replacement. The existing relays were replaced at different times. The budgetary cost (purchase price) does not include installation and the other related expenses to implement the project. The years shown are in accordance with 20 years life expectancy of the relays.

TRANSMISSION STATION	BUDGETARY COST (US$)	YEAR OF RELAYS REPLACEMENT (End of Life Expectancy)
ANJIGAMI TS	109,069	2011
CLERGUE TS	169,323	2011, 2013, 2028
ECHO RIVER	35,145	2029
GARTSHORE TS	114,738	2026
HOLLINGSWORTH TS	55,726	2011, 2025
HWY. 101 TS	7,391	2015
230kV MACKAY TS	120,476	2026
115kV MACKAY TS	262,697	2028
MAGPIE TS	107,773	2011, 2028
NORTHERN AV. TS	30,605	2024
STEELTON TS	173,602	2025
230kV THIRD LINE TS	177,363	2025, 2026
115kV THIRD LINE TS	262,603	2030
WATSON TS	150,663	2011
TOTAL BUDGETARY COST OF RELAYS (US$)	$1,777,174	Life Expectancy: 20 Yrs.

Elaborated details of budgetary cost for each station against years are given in **Appendices-C & D**. The twenty years life expectancy period is divided into four quarters to facilitate expedited replacement program.

Graphical Representation of Budgetary Cost (Purchase Price) of the proposed protective relays:



APPENDIX A

Inventory of Existing Relays

Inventory of Existing Protective Relays

Great Lakes Power Transmission

Protective Relays Replacement Study – OLE Project No. 10-003

Station Name	Alstom P Series Relays (MiCOM)									AREVA/Alstom Relays						SEL Relays													ABB, Basler, GE & Westinghouse Relays									Total Relays
	P122 O/C (BF)	P141 Dir. O/C	P143 Dir. O/C	P441 Dist. Prot.	P442 Dist. Prot.	P521 +P592 Line Diff.	P543 Line Diff.	P633 T/F Diff.	MCTI O/C (BF)	KCEG 112 E/F	KCEG 140 Dir. O/C	KCEG 142 Dir. O/C	KBCH 120 T/F Diff.	MFAC Bus Diff.	MCAG Bus Diff.	SEL-311C Dist. Prot.	SEL-311L Line Diff.	SEL-321 Dist. Prot.	SEL-351 Dir. O/C	SEL-351A Dir. O/C	SEL-352 (BF)	SEL-387E T/F Diff.	SEL-387L Line Diff.	SEL-551 O/C	SEL-551C O/C	SEL-487E T/F Diff.	SEL-587Z Bus Diff.	SEL-251D Dist.	F60 (GE) Dir. O/C	T60 (GE) T/F Diff.	745 (GE) T/F Diff.	OPTI-MHO (GE) Dist.	IJS & IAC Synch. & O/C	BDD (GE) Bus Diff.	W/H Bus Diff.	BE1-25A Basler Synch.	CO-11 (ABB) O/C	
Andrews TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	No Relays
Anjigami TS	-	-	-	3	-	-	-	-	-	-	5		1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Batcha-wana TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	No Relays
Clergue TS	2	4	-	-	-	-	4	-	2	2	-	-	-	-	-	-	2	-	-	-		2	2	2	2	-	-	-	-	-	-	-	1+2	-	-	-	-	27
Echo River TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	1	-	-	2	1	-	-	-	-	-	-	-	5
Goulais TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	No Relays
Gartsh-ore TS	-	-	-	-	4	-	1	-	-	-	-	-	-	-	-	4	1	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15
Hollings-worth TS	-	1	-	-	-	-	-	-	-	-	1	-	1	1	-	-	-	-	-	1	-	1	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	8
Hwy. 101 TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
MacKay TS	-	2	-	2	3	-	2	-	-	-	-	-	-	1	1	3	2	2	1	-	11	1	-	-	-	-	2	-	-	-	1	-	-	-	-	-	-	34
Magpie TS	4	-	-		4	-	-	-	-	-	1	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12
North-ern Av. TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	2	-	-	-	1	-	-	-	-	-	-	-	-	-	5
Steelton TS	4	-	-	1	-	3	2	-	-	-	-	-	-	-	-	1	5	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	2	2	-	-	29
Third Line TS	7	9	1	3	-	3	-	2	-	-	1	-	-	4	2	-	3	3	2	2	5	2	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	55
Watson TS	-	4	-	-	-	-	-	-	-	-	10	9	2	2	-	-	-	-	-	-	-	-	--	-	-	-	-	-	-	-	-	-	-	-	-	1	-	28
Total Relays	17	20	1	9	11	6	9	2	2	2	18	9	4	9	3	11	13	5	3	3	22	8	2	6	11	1	2	1	2	1	1	6	3	2	2	1	4	232

Note: **1. Total Number of Protective Relays: 232 (Auxiliary relays are not included).**

2. Electro-mechanical Relays: Anjigami TS, Clergue TS, Steelton TS, Hollingsworth TS, Hwy. 101 TS, Magpie TS, Third Line TS and Watson TS.

3. Static Relays: Clergue TS, Third Line TS and Watson TS

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

APPENDIX B

Replacement Plan & Schedule

Relays Replacement Plan and Schedule

ITEM NO.	TRANSMISASION STATION	YEAR OF ACTIVITY																			
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Andrews TS										No Protective Relays										
2	Anjigami TS	KCEG 140				MFAC KBCH 120							MiCOM								New Relays GE/SEL
3	Batchawana TS										No Protective Relays										
4	Clergue TS	IJS/IAC		KCEG 112 MCTI															SEL MiCOM		
5	Echo River																			GE/SEL	
6	Gartshore TS																SEL MiCOM				
7	Goulais TS										No Protective Relays										
8	Hollingsworth TS	KCEG 140				MFAC				KBCH 120						SEL MiCOM					
9	Hwy. 101 TS					CO-11															
10	MacKay TS																MCAG/MFAC SEL MiCOM		SEL MiCOM		
11	Magpie TS	KCEG 140																	SEL MiCOM		
12	Northern Av. TS														SEL						
13	Steelton TS			BDD, W/H												SEL MiCOM					
14	Third Line TS	KCEG 140 OPTIMHO OPTIMHO											MiCOM		SEL MiCOM	MCAG/MFAC SEL MiCOM					115kV New Relays GE/SEL
15	Watson TS	KCEG 140 BE1-25A							KCEG 142 MFAC 34		KCEG 142		MiCOM								New Relays GE/SEL KCEG 142

Legend: ● Obsolete Relays ● Electro-mechanical Relays
● Static Relays ● End of Lifespan Relays

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3R4
Phone: 905-688-6857

APPENDIX C

Budgetary Cost – Purchase Price

Budgetary Cost (Purchase Price) of New Protective Relays

Great Lakes Power Transmission

Protective Relays Replacement Study -- OLE Project No. 10-003

Sation Name	1st Five Year Period					2nd Five Year Period					3rd Five Year Period					4th Five Year Period					Budgetary Cost (Purchase Price) US$
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
Andrews TS		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	No Protective Relays
Anjigami TS	109,069	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	109,069
Batchawana TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	No Protective Relays
Clergue TS	3,933	-	26,782	-	-	-	-	-	-	-	22,164	-	-	-	-	-	-	116,444	-	-	169,323
Echo River TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35,145	-	35,145
Goulais TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	No Protective Relays
Gartshore TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	114,738	-	-	-	-	114,738
Hollingsworth TS	4,350	-	-	-	-	-	8,860	-	5,782	-	-	-	-	-	36,734	-	-	-	-	-	55,726
Hwy. 101 TS	-	-	-	-	7,391	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,391
230KV Mackay TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120,476	-	-	-	-	120,476
115KV Mackay TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	262,697	-	-	262,697
Magpie TS	11,050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	96,723	-	-	107,773
Northern Av. TS	-	-	-	-	-	-	-	-	-	-	-	-	-	30,605	-	-	-	-	-	-	30,605
Steelton TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	173,602	-	-	-	-	-	173,602
230KV Third Line TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	156,363	21,000	-	-	-	-	177,363
115KV Third Line TS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	262,603	262,603
Watson TS	150,663	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150,663
Budgetary Cost (Purchase Price)	279,065	-	26,782	-	7,391	-	8,860	-	5,782	-	22,164	-	-	30,605	366,699	256,214	-	475,864	35,145	262,603	1,777,174

APPENDIX D

Replacement Program

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Anjigami TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

ANJIGAMI TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Anjigami TS**	**115KV HIGH FALLS NO.1**	**A**	MiCOM P441	**GE/D60**	**12,042**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	""	115KV HIGH FALLS NO.1	**B**	ALSTOM/KCEG 140	**SEL/SEL-421-5**	**11,050**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																									
4	""	**115KV HIGH FALLS NO.2**	**A**	MiCOM P441	**GE/D60**	**12,042**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	""	115KV HIGH FALLS NO.2	**B**	ALSTOM/KCEG 140	**SEL/SEL-421-5**	**11,050**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6																									
7	""	**115KV HOLLINGSWORTH LINE**	**A**	MiCOM P441	**GE/D60**	**12,042**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	""	115KV HOLLINGSWORTH LINE	**B**	ALSTOM/KCEG 140	**SEL/SEL-421-5**	**11,050**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																									
10	""	**115KV/44KV TRANSFORMER**	**A**	ALSTOM/KBCH120	**GE/T35**	**5,782**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	""	115KV/44KV TRANSFORMER	**B**	ALSTOM/KCEG140	**SEL/SEL-487E**	**8,860**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																									
13	""	**115KV BUS BAR**	**A**	ALSTOM/MFAC	**GE/B90**	**11,465**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	""	115KV BUS BAR	**B**	N/A	**SEL/SEL-587Z**	**4,350**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																									
16	""	**44KV JAGER LINE**	**A**	ALSTOM/KCEG140	**GE/F60**	**7,353**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	""	44KV JAGER LINE	**B**	N/A	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																									
19																									
20	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$109,069**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Clergue TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

CLERGUE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Clergue TS**	**115KV CLERGUE LINE NO. 1**	**A**	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-
2	""	115KV CLERGUE LINE NO. 1	**A**	SEL/SEL-387L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-
3	""	115KV CLERGUE LINE NO. 1	**B**	MiCOM P543	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-
4	""	115KV CLERGUE LINE NO. 1	**B**	MiCOM P543	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-
5																									
6	""	**115KV CLERGUE LINE NO. 2**	**A**	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-
7	""	115KV CLERGUE LINE NO. 2	**A**	SEL/SEL-387L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-
8	""	115KV CLERGUE LINE NO. 2	**B**	MiCOM P543	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-
9	""	115KV CLERGUE LINE NO. 2	**B**	MiCOM P543	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-
10																									
11	""	**115KV COGEN LINE NO. 1**	**A**	KCEG112	**GE/F60**	-	-	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12		115KV COGEN LINE NO. 1	**B**	NOT AVAILABLE	**SEL/SEL-451-5**	-	-	**7,850**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	""	115KV COGEN LINE NO. 1	**BF**	GE/MCTI	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	""																								
15		**115KV COGEN LINE NO. 2**	**A**	KCEG112	**GE/F60**	-	-	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	""	115KV COGEN LINE NO. 2	**B**	NOT AVAILABLE	**SEL/SEL-451-5**	-	-	**7,850**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	""	115KV COGEN LINE NO. 2	**BF**	GE/MCTI	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																									
19																									
20																									

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Clergue TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

CLERGUE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
21	**Clergue TS**	**115KV/12KV XFMR MT1**	**A**	SEL/SEL-387E	**GE/T35**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,782**	-	-
22	""	115KV/12KV XFMR MT1	**B**	SEL/SEL-551	**SEL/SEL-487E**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**6,750**	-	-
23	""	115KV/12KV XFMR MT1	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																									
25	""	**115KV/12KV XFMR MT2**	**A**	SEL/SEL-387E	**GE/T35**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,782**	-	-
26	""	115KV/12KV XFMR MT2	**B**	SEL/SEL-551	**SEL/SEL-487E**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**6,750**	-	-
27	""	115KV/12KV XFMR MT2	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28																									
29	""	**12KV BUS NO. 1**	**A**	MiCOM P122	**SEL/SEL-751A**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**950**	-	-
30		12KV BUS NO. 1	**B**	NOT AVAILABLE	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																									
32	""	**12KV BUS NO. 2**	**A**	MiCOM P122	**SEL/SEL-751A**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**950**	-	-
33	""	12KV BUS NO. 2	**B**	NOT AVAILABLE	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34																									
35	""	**12KV BUS TIE**	**SYNCHRO-CHECK**	GE/IJS	**GE/MLJ**	**2,033**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-
36																									
37																									
38																									
39																									
40																									

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Clergue TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

CLERGUE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
41	**Clergue TS**	**12KV PAPER CO. 1**	**A**	MiCOM P141	**GE/F60**	-	-	-	-	-	-	-	-	-	-	**5,541**	-	-	-	-	-	-	-	-	-
42	""	12KV PAPER CO. 1	**B**	NOT AVAILABLE	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43																									
44	""	**12KV PAPER CO. 2**	**A**	MiCOM P141	**GE/F60**	-	-	-	-	-	-	-	-	-	-	**5,541**	-	-	-	-	-	-	-	-	-
45	""	12KV PAPER CO. 2	**B**	NOT AVAILABLE	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46																									
47	""	**12KV PAPER CO. 3**	**A**	MiCOM P141	**GE/F60**	-	-	-	-	-	-	-	-	-	-	**5,541**	-	-	-	-	-	-	-	-	-
48	""	12KV PAPER CO. 3	**B**	NOT AVAILABLE	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49																									
50	""	**12KV PAPER CO. 4**	**A**	MiCOM P141	**GE/F60**	-	-	-	-	-	-	-	-	-	-	**5,541**	-	-	-	-	-	-	-	-	-
51	""	12KV PAPER CO. 4	**B**	NOT AVAILABLE	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52																									
53		**12KV STATION SERVICE 1**	**A**	GE/IAC	**SEL/SEL-751A**	**950**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54		12KV STATION SERVICE 1	**B**	NOT AVAILABLE	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55																									
56		**12KV STATION SERVICE 2**	**A**	GE/IAC	**SEL/SEL-751A**	**950**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57		12KV STATION SERVICE 2	**B**	NOT AVAILABLE	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58																									
59																									
60	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$169,323**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Echo River TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

ECHO RIVER TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Echo River TS**	**230KV/115KV/34.5KV XFMR.**	**A**	GE/T60	**GE/T60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7,353**	-
2	""	230KV/115KV/34.5KV XFMR.	**B**	SEL/SEL-487E	**SEL/SEL-487E**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,860**	-
3																									
4	""	**230KV BREAKER FAILURE**	**A**	SEL/SEL-352	**SEL/SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7,850**	-
5	""	230KV BREAKER FAILURE	**B**	Not Required		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6																									
7	""	**34.5KV FEEDER NO.1**	**A**	GE/F60	**GE/F60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,541**	-
8	""	34.5KV FEEDER NO.1	**B**	Not Required	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																									
10	""	**34.5KV FEEDER NO.2**	**A**	GE/F60	**GE/F60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,541**	-
11	""	34.5KV FEEDER NO.2	**B**	Not Required	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																									
13																									
14																									
15																									
16																									
17																									
18																									
19																									
20	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$35,145**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Gartshore TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

GARTSHORE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Gartshore TS	**115KV GARTSHORE TS - MACKAY TS NO.1**	A	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-	-	-
2	""	115KV GARTSHORE TS - MACKAY TS NO.1	B	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-
3																									
4	""	**115KV GARTSHORE TS - MACKAY TS NO.2**	A	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-	-	-
5	""	115KV GARTSHORE TS - MACKAY TS NO.2	B	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-
6																									
7	""	**115KV ANDREWS LINE-ANDREWS GS**	A	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-	-	-
8	""	115KV ANDREWS LINE-ANDREWS GS	B	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-
9																									
10	""	**115KV HOGG LINE - HOGG GS**	A	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-	-	-
11	""	115KV HOGG LINE - HOGG GS	B	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-
12																									
13	""	**115KV GARTSHORE TS - GARTSHORE GS**	A	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-	-	-
14	""	115KV GARTSHORE TS - GARTSHORE GS	B	MiCOM P543	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-	-	-
15																									
16																									
17																									
18																									
19																									
20	**TOTAL REPLACEMENT COST (US$)**					**$114,738**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Gartshore TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

GARTSHORE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
21	**Gartshore TS**	**115KV BREAKER FAILURE**				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	""	**BREAKER FAILURE BF 52-1410**	**BF**	SEL/SEL-352	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	""	**BREAKER FAILURE BF 52-1418**	**BF**	SEL/SEL-352	**NOT REQUIRED**																				
24	""	**BREAKER FAILURE BF 52-1402**	**BF**	SEL/SEL-352	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	""	**BREAKER FAILURE BF 52-1414**	**BF**	SEL/SEL-352	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	""	**BREAKER FAILURE BF 52-1406**	**BF**	SEL/SEL-352	**NOT REQUIRED**																				
27						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																									
30						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																									
33						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35																									
36						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38																									
39						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$114,738**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: Great Lakes Power Transmission Ltd. (GLPT)
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Hollingsworth TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

HOLLINGSWORTH TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Hollingsworth TS	115KV HOLLINGSWORTH LINE	A	SEL/SEL-351A	GE/D60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12,042	-	-	-	-	-
2	""	115KV HOLLINGSWORTH LINE	B	MiCOM P141	SEL/SEL-421-5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11,050	-	-	-	-	-
3																									
4	""	115KV/11.5KV TRANSFORHER T1	A	SEL/SEL-387E	GE/T35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,782	-	-	-	-	-
5	""	115KV/11.5KV TRANSFORHER T1	B	SEL/SEL-551	SEL/SEL-487E	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,860	-	-	-	-	-
6																									
7	""	115KV/44KV TRANSFORHER T2	A	ALSTOM/KBCH120	GE/T35	-	-	-	-	-	-	-	-	5,782	-	-	-	-	-	-	-	-	-	-	-
8	""	115KV/44KV TRANSFORHER T2	B	ALSTOM/KCEG140	SEL/SEL-487E	-	-	-	-	-	-	8,860	-	-	-	-	-	-	-	-	-	-	-	-	-
9																									
10	""	11.5KV BUS 1	A	ALSTOM/MFAC	SEL/587Z	-	-	-	-	4,350	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	""	11.5KV BUS 1	B	-	NOT REQUIRED	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-
12																									
13	""	115KV BREAKER FAILURE				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	""	50BF-52-999	BF	SEL/SEL-551	NOT REQUIRED	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																									
16																									
17																									
18																									
19																									
20	TOTAL BUDGETRY COST-PURCHASE PRICE (US $):					$56,726																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Hwy. 101 TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

HWY. 101 TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Hwy. 101 TS**	**44KV LIMER LINE**	**A**	ABB/CO-11 HILO	**GE/F60**	-	-	-	-	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	""	44KV LIMER LINE	**B**	N/A	**SEL/SEL-351S**	-	-	-	-	**1,850**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																									
4																									
5																									
6																									
7																									
8																									
9																									
10																									
11																									
12																									
13																									
14																									
15																									
16																									
17																									
18																									
19																									
20	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$7,391**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **MacKay TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

MACKAY TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**MacKay TS**	**23oKV MACKAY TS - 3RD LINE TS**	**A**	MiCOM P441	**GE/D90plus**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**21,399**	-	-	-	-
2	""	23oKV MACKAY TS - 3RD LINE TS	**B**	SEL/SEL-321	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-
3																									
4	""	**23oKV MACKAY TS - WAWA TS**	**A**	MiCOM P441	**GE/D90plus**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**21,399**	-	-	-	-
5	""	23oKV MACKAY TS - WAWA TS	**B**	SEL/SEL-321	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-
6																									
7	""	**230KV/115KV/34.5KV XFMR T2**	**A**	GE/745	**GE/T60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7,353**	-	-	-	-
8	""	230KV/115KV/34.5KV XFMR T2	**B**	SEL/SEL-387E	**SEL/SEL-487E**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,860**	-	-	-	-
9																									
10	""	**230KV BUS T2H**	**A**	AREVA/MCAG	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**	-	-	-	-
11	""	230KV BUS T2H	**B**	AREVA/MFAC	**SEL/SEL-587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**4,350**	-	-	-	-
12																									
13	""	**230KV BREAKER FAILURE**	**-**			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	""	**52-678 BREAKER TIE**	**-**	SEL/SEL-352	**SEL/SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7,850**	-	-	-	-
15		**52-682 BREAKER K24G**	**-**	SEL/SEL-352	**SEL/SEL-451-5**																**7,850**				
16	""	**52-690 BREAKER W23K**	**-**	SEL/SEL-352	**SEL/SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7,850**	-	-	-	-
17																									
18	""	**115KV SAULT NO.3**	**A**	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-
19	""	115KV SAULT NO.3	**B**	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-
20						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **MacKay TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

MACKAY TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
21	**MacKay TS**	**115KV GARTSHORE TS NO. 1**	**A**	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-
22	""	115KV GARTSHORE TS NO. 1	**B**	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-
23																									
24	""	**115KV GARTSHORE TS NO. 2**	**A**	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-
25	""	115KV GARTSHORE TS NO. 2	**B**	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-
26																									
27	""	**115KV MACKAY NO. 1**	**A**	MiCOM P543	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-
28	""	115KV MACKAY NO. 1	**B**	SEL/SEL-311L	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-
29																									
30	""	**115KV MACKAY NO. 2**	**A**	MiCOM P543	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-
31	""	115KV MACKAY NO. 2	**B**	SEL/SEL-311L	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-
32																									
33	""	**115KV BUS BAR NORTH**	**A**	SEL/SEL-587Z	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**	-	-
34	""	115KV BUS BAR NORTH	**B**	MiCOM P141	**SEL/SEL-587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**	-	-
35																									
36	""	**115KV BUS BAR SOUTH**	**A**	SEL/SEL-587Z	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**	-	-
37	""	115KV BUS BAR SOUTH	**B**	MiCOM P141	**SEL/SEL-587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**	-	-
38																									
39																									
40	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$262,697**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Magpie TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

MAGPIE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Magpie TS**	**115KV HIGH FALLS NO.1**	**A**	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-
2	""	115KV HIGH FALLS NO.1	**B**	ALSTOM/KCEG140	**SEL/SEL-421-5**	-	-	-	**11,050**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																									
4	""	**115KV MISSION LINE**	**A**	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-
5	""	115KV MISSION LINE	**B**	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-
6																									
7	""	**115KV STEEPHILL LINE**	**A**	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-
8	""	115KV STEEPHILL LINE	**B**	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-
9																									
10	""	**115KV HARRIS LINE**	**A**	MiCOM P442	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-
11	""	115KV HARRIS LINE	**B**	SEL/SEL-311C	**SEL/SEL-421-5**	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-
12																									
13	""	**115KV BUS PROTECTION**	**A**	**NOT AVAILABLE**	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**	-	-
14	""	115KV BUS PROTECTION	**B**	**NOT AVAILABLE**	**SEL/SEL-587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**	-	-
15																									
16																									
17																									
18																									
19																									
20	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$107,773**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Northern Av. TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

NORTHERN AV. TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Northern Av. TS**	**115KV/34.5KV TRANSFORMER T1**	**A**	SEL/SEL-387E	**GE/T35**	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,782**	-	-	-	-	-	-
2	""	115KV/34.5KV TRANSFORMER T1	**B**	SEL/SEL-551	**SEL/SEL-487E**	-	-	-	-	-	-	-	-	-	-	-	-	-	**6,750**	-	-	-	-	-	-
3																									
4	""	**115KV/34.5KV TRANSFORMER T2**	**A**	SEL/SEL-387E	**GE/T35**	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,782**	-	-	-	-	-	-
5	""	115KV/34.5KV TRANSFORMER T2	**B**	SEL/SEL-551	**SEL/SEL-487E**	-	-	-	-	-	-	-	-	-	-	-	-	-	**6,750**	-	-	-	-	-	-
6																									
7	""	**12KV GLP DISTRIBUTION**	**A**	SEL/SEL-251D	**GE/F60**	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,541**	-	-	-	-	-	-
8	""	12KV GLP DISTRIBUTION	**B**	NOT REQUIRED	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																									
10																									
11																									
12																									
13																									
14																									
15																									
16																									
17																									
18																									
19																									
20	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$30,605**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Steelton TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

STEELTON TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Steelton TS**	**115KV AL-GOMA NO. 1**	**A**	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-	-	-	-
2	""	115KV AL-GOMA NO. 1	**B**	MiCOM P521	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-	-	-	-
3																									
4	""	**115KV AL-GOMA NO. 2**	**A**	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-	-	-	-
5	""	115KV AL-GOMA NO. 2	**B**	MiCOM P521	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-	-	-	-
6																									
7	""	**115KV AL-GOMA NO. 3**	**A**	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-	-	-	-
8	""	115KV AL-GOMA NO. 3	**B**	MiCOM P521	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-	-	-	-
9																									
10	""	**115KV CLERGUE NO. 1**	**A**	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-	-	-	-
11	""	115KV CLERGUE NO. 1	**B**	MiCOM P521	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-	-	-	-
12																									
13	""	**115KV CLERGUE NO. 2**	**A**	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14,370**	-	-	-	-	-
14	""	115KV CLERGUE NO. 2	**B**	MiCOM P543	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**	-	-	-	-	-
15																									
16	""	**115KV LEIGH'S BAY**	**A**	SEL/SEL-311C	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**12,042**	-	-	-	-	-
17	""	115KV LEIGH'S BAY	**B**	MiCOM P441	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-	-
18																									
19	""	**115KV BUS NO. 1**	**R-ø**	WESTINGHOUSE 671B157A18	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**	-	-	-	-	-
20	""	115KV BUS NO. 1	**Y-Ø**	WESTINGHOUSE 671B157A18	**SEL/SEL-587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**	-	-	-	-	-

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Steelton TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

STEELTON TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
21	**Steelton TS**	**115KV BUS NO. 2**	**B-Ø**	GE/BDD	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**	-	-	-	-	-
22	""	115KV BUS NO. 2	**Y-Ø**	GE/BDD	**SEL/SEL-587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**	-	-	-	-	-
23																									
24	""	**115KV BKR. FAILURE-PANEL 1**																							
25	""	**B-BF-52-222**	**BF**	MiCOM P122	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	""	**B-BF-52-232**	**BF**	MiCOM P122	**SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7,850**	-	-	-	-	-
27	""	**B-BF-52-242**	**BF**	MiCOM P122	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	""	**B-BF-52-245**	**BF**	MiCOM P122	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	""	**A50-62BF-205**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	""	**A50-62BF-208**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	""	**A50-62BF-211**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	""	**A50-62BF-225**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	""	**A50-62BF-214**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	""	**A50-62BF-217**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	""	**A50-62BF-228**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	""	**A50-62BF-235**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	""	**A50-62BF-248**	**BF**	SEL/SEL-551C	**NOT REQUIRED**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38																									
39																									
40	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$173,602**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Third Line TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

THIRD LINE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Third Line TS**	**230KV LINE P21G - MISSISAGI TS**	**A**	MiCOM P441	**GE/D90PLUS**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**21,399**	-	-	-	-	-
2	""	230KV LINE P21G - MISSISAGI TS	**B**	SEL/SEL-321	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-	-
3																									
4	""	**230KV LINE P22G - MISSISAGI TS**	**A**	MiCOM P441	**GE/D90PLUS**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**21,399**	-	-	-	-	-
5	""	230KV LINE P22G - MISSISAGI TS	**B**	SEL/SEL-321	**SEL/SEL-421**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-	-
6																									
7	""	**230KV LINE K24G - MACKAY TS**	**A**	MiCOM P441	**GE/D90PLUS**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**21,399**	-	-	-	-	-
8	""	230KV LINE K24G - MACKAY TS	**B**	SEL/SEL-321	**SEL/SEL-421**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**	-	-	-	-	-
9																									
10	""	**230KV/115KV TRANSFOTEMR T1**	**A**	MiCOM P633	**GE/T60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7,353**	-	-	-	-	-
11	""	230KV/115KV TRANSFOTEMR T1	**B**	SEL/SEL-387E	**SEL/SEL-487E**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**6,750**	-	-	-	-	-
12																									
13	""	**230KV/115KV TRANSFOTEMR T2**	**A**	MiCOM P633	**GE/T60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7,353**	-	-	-	-	-
14	""	230KV/115KV TRANSFOTEMR T2	**B**	SEL/SEL-387E	**SEL/SEL-487E**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**6,750**	-	-	-	-	-
15																									
16	""	**230KV BUS T1H**	**A**	AREVA/MCAG	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**	-	-	-	-	-
17	""	230KV BUS T1H	**B**	AREVA/MFAC	**SEL/SEL-587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**	-	-	-	-	-
18																									
19	""	**230KV BUS T2H**	**A**	AREVA/MCAG	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**	-	-	-	-	-
20	""	230KV BUS T2H	**B**	AREVA/MFAC	**SEL/SEL-587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**	-	-	-	-	-

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Third Line TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

THIRD LINE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
21	**Third Line TS**	**230KV BREAKER FAILURE**																							
22	""	**52-402 BREAKER**	-	SEL/SEL-352	**SEL/SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**4,200**	-	-	-	-
23		**52-405 BREAKER**	-	SEL/SEL-352	**SEL/SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**4,200**	-	-	-	-
24	""	**52-408 BREAKER**	-	SEL/SEL-352	**SEL/SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**4,200**	-	-	-	-
25	""	**52-412 BREAKER**	-	SEL/SEL-352	**SEL/SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**4,200**	-	-	-	-
26		**52-415 BREAKER**	-	SEL/SEL-352	**SEL/SEL-451-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**4,200**	-	-	-	-
27																									
28	""	**115KV AL-GOMA NO.1**	**A**	SEL/SEL-311L	**GE/L90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**18,708**
29	""	115KV AL-GOMA NO.1	**B**	MiCOM P521	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**
30																									
31	""	**115KV AL-GOMA NO.2**	**A**	SEL/SEL-311L	**GE/L90**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**18,708**
32	""	115KV AL-GOMA NO.2	**B**	MiCOM P521	**SEL/SEL-411L**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**8,000**
33																									
34	""	**115KV NORTHERN AVENUE**	**A**	GEC/OPTIMHO	**GE/D60**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**16,380**
35	""	115KV NORTHERN AVENUE	**B**	MiCOM P141	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**
36																									
37	""	**115KV SAULT NO.3**	**A**	GEC/OPTIMHO	**GE/D60**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**16,380**
38	""	115KV SAULT NO.3	**B**	ALSTOM/KCEG140	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**
39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Third Line TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

THIRD LINE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
41	**Third Line TS**	**115KV GL1 SM**	**A**	GEC/OPTIMHO	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**16,380**
42	""	115KV GL1 SM	**B**	MiCOM P141	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**
43																									
44	""	**115KV GL2 SM**	**A**	GEC/OPTIMHO	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**16,380**
45	""	115KV GL2 SM	**B**	MiCOM P141	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**
46																									
47	""	**115KV GL1 TA**	**A**	GEC/OPTIMHO	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**16,380**
48	""	115KV GL1 TA	**B**	MiCOM P141	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**
49																									
50	""	**115KV GL2 TA**	**A**	GEC/OPTIMHO	**GE/D60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**16,380**
51	""	115KV GL2 TA	**B**	MiCOM P141	**SEL/SEL-421-5**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,050**
52																									
53	""	**115KV BUS - NORTH BUS**	**A**	ALSTOM/MFAC	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**
54	""	115KV BUS - NORTH BUS	**B**	MiCOM P141	**SEL/SEL587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**
55																									
56	""	**115KV BUS - SOUTH BUS**	**A**	ALSTOM/MFAC	**GE/B90**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**11,465**
57	""	115KV BUS - SOUTH BUS	**B**	MiCOM P141	**SEL/SEL587Z**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**3,940**
58																									
59	-	**SYNCHRO-CHECK/CONTROL**	-	MiCOM P143	**GE/MLJ**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**2,033**
60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Third Line TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

THIRD LINE TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
61	**Third Line TS**	**LOAD SHEDDING**	-	MiCOM P122	**GE/N60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,882**
62																									
63	""	**115KV BREAKER FAILURE**	-																						
64	""	**BREAKER FAILURE 1604 & 1607**	-	MiCOM P122	**GE/C60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,882**
65	""	**BREAKER FAILURE 1610 & 1613**	-	MiCOM P122	**GE/C60**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**5,882**
66	""		-																						
67																									
68																									
69																									
70																									
71																									
72																									
73																									
74																									
75																									
76																									
77																									
78																									
79																									
80	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$445,848**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program and Budgetary Cost

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Watson TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

WATSON TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	**Watson TS**	**115KV HIGH FALLS No. #1**	**A**	ALSTOM/KCEG140	**GE/D60**	**12,042**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	""	115KV HIGH FALLS No. #1	**B**	ALSTOM/KCEG140	**SEL/SEL-421-5**	**11,050**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3																									
4	""	**115KV HIGH FALLS No. # 2**	**A**	ALSTOM/KCEG140	**GE/D60**	**12,042**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	""	115KV HIGH FALLS No. # 2	**B**	N/A	**SEL/SEL-421-5**	**11,050**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6																									
7	""	**115KV/34.5KV TRANSFORMER T1**	**A**	ALSTOM/KBCH120	**GE/T35**	**5,782**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	""	115KV/34.5KV TRANSFORMER T1	**B**	ALSTOM/KCEG140	**SEL/SEL-387E**	**5,780**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																									
10	""	**115KV/34.5KV TRANSFORMER T2**	**A**	ALSTOM/KBCH120	**GE/T35**	**5,782**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	""	115KV/34.5KV TRANSFORMER T2	**B**	ALSTOM/KCEG140	**SEL/SEL-387E**	**5,780**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12																									
13	""	**34.5KV WAWA NO. 1**	**A**	AREVA/KCEG142	**GE/F60**	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	""	34.5KV WAWA NO. 1	**B**	ALSTOM/KCEG142	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																									
16	""	**34.5KV WAWA NO. 2**	**A**	AREVA/KCEG140	**GE/F60**	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	""	34.5KV WAWA NO. 2	**B**	AREVA/KCEG142	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18																									
19	""	**34.5KV SCOTT NO. 1**	**A**	AREVA/KCEG142	**GE/F60**	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	""	34.5KV SCOTT NO. 1	**B**	AREVA/KCEG142	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program and Budgetary Cost

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Watson TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

WATSON TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
21	**Watson TS**	**34.5KV SCOTT NO. 2**	**A**	ALSTOM/KCEG142	**GE/F60**	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	""	34.5KV SCOTT NO. 2	**B**	ALSTOM/KCEG140	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23																									
24	""	**34.5KV McPHAIL NO. 1**	**A**	ALSTOM/KCEG140	**GE/F60**	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	""	34.5KV McPHAIL NO. 1	**B**	ALSTOM/KCEG142	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26																									
27	""	**34.5KV McPHAIL NO. 2**	**A**	ALSTOM/KCEG142	**GE/F60**	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	""	34.5KV McPHAIL NO. 2	**B**	ALSTOM/KCEG142	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29																									
30	""	**34.5KV DUNFORD NO. 1**	**A**	ALSTOM/KBCH120	**GE/F60**	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	""	34.5KV DUNFORD NO. 1	**B**	ALSTOM/KCEG140	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																									
33	""	**34.5KV DUNFORD NO. 2**	**A**	AREVA/KCEG142	**GE/F60**	**5,541**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	""	34.5KV DUNFORD NO. 2	**B**	ALSTOM/KCEG142	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35																									
36	""	**34.5KV BUS 1**	**A**	ALSTOM/MFAC	**GE/MIB**	**2,647**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	""	34.5KV BUS 1	**B**	ALSTOM/KCEG140	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38																									
39	""	**34.5KV BUS 2**	**A**	ALSTOM/MFAC	**GE/MIB**	**2,647**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	""	34.5KV BUS 2	**B**	ALSTOM/KCEG140	**SEL/SEL-351S**	**2,550**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

Relays Replacement Program and Budgetary Cost

Client: **Great Lakes Power Transmission Ltd. (GLPT)**
OLE Project No. 10-003 - **Replacement of Protective Relays Study**
GLPT Addendum No. 2010-015-A1004
Transmission Station: **Watson TS** - Recommended New Relays
GLPT Manager System Planning & Eng. Dept: Gary Gazankas
GLPT Project Managers: Dan Sutton/Jim Tait

WATSON TS						Suggested Year of Relays Replacement and Budgetary Cost (US $)																			
Item	Transmission Station	Feeder / XFMR / Bus	A or B Protection	Existing Relay / Type Manufacture	Replace By	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
41	**Watson TS**	**34.5KV BUS TIE BUS 1/BUS 2**	**SYNCHRO-CHECK**	N/A	**GE/MLJ**	**2,033**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	""	**34.5KV SYNCHRONIZER**	-	BASLER/BE1-25A	**SEL/SEL-451**	**4,200**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44																									
45																									
46																									
47																									
48																									
49																									
50																									
51																									
52																									
53																									
54																									
55																									
56																									
57																									
58																									
59																									
60	**TOTAL BUDGETRY COST-PURCHASE PRICE (US $):**					**$150,663**																			

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catharines, ON L2R 3C4
Phone: 905-688-6857

APPENDIX E

GLPT Relays Data – Quick Reference

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RTU MAKE	RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**ANDREWS TS**						
2	""	**NO PROTECTION RELAYS**	NO PROTECTION RELAYS	-	-	-	**-**
3							
4	""	REMOTE TERMINAL UNIT	COMMUNICATES VIA ANDREWS GS JUNGLEMUX	GE	iBox Serial	2005	**NO REPLACEMENT**
5							
6	""	I/O MODULE	""	SEL	SEL-2505	2005	**NO REPLACEMENT**
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 90-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**ANJIGAMI TS**						
2	""	**115KV HIGH FALLS LINE #1**	A' PROTECTION	ALSTOM	MiCOM P441	2002	**GE/D60**
3	""	115KV HIGH FALLS LINE #1	B' PROTECTION & BF	GE ALSTOM	KCEG 140	1995	**SEL-421-5**
4							
5	""	**115KV HIGH FALLS LINE #2**	A' PROTECTION	ALSTOM	MiCOM P441	2002	**GE/D60**
6	""	115KV HIGH FALLS LINE #2	B' PROTECTION & BF	GE ALSTOM	KCEG 140	1995	**SEL-421-5**
7							
8	""	**115KV HOLLINGSWORTH LINE**	A' PROTECTION	ALSTOM	MiCOM P441	2002	**GE/D60**
9	""	115KV HOLLINGSWORTH LINE	B' PROTECTION & BF	GE ALSTOM	KCEG 140	1995	**SEL-421-5**
10							
11	""	**115KV/44KV TRANSF. (40/53.3MVA)**	A' PROTECTION	ALSTOM	KBCH120	1995	**GE/T35**
12	""	115KV/44KV TRANSFORMER	B' PROTECTION & BF	ALSTOM	KCEG 140	1995	**SEL-487E**
13							
14	""	**115KV BUS BAR**	A' PROTECTION	ALSTOM	MFAC	1995	**GE/B90**
15	""	115KV BUS BAR	B' PROTECTION	N/A	N/A	-	**SEL-587Z**
16							
17	""	**44KV JAGER LINE**	A' PROTECTION	ALSTOM	KCEG 140	1995	**GE/F60**
18	""	44KV JAGER LINE	B' PROTECTION	N/A	N/A	-	**SEL-351S**
19							
20	""						
21	""						
22							
23	""	**RTU PANEL**	REMOTE TERMINAL UNIT	GE HARRIS	WESDAC D20 ME	-	**SEL-3354**
24	""			GE HARRIS	I/O MODULES	-	**-**
25							
26	""	**JUNGLEMUX**	FIBRE OPTICAL COMMUNICATION	NORTEL	86400 JUNGLEMUX	-	**NO REPLACEMENT**
27							
28	""	**RUGGEDCOM**	RUGGED SWITCH	RUGGEDCOM	RSG2100	-	**NO REPLACEMENT**
29	""	RUGGEDCOM	RUGGED ROUTER	RUGGEDCOM	RX110	-	**NO REPLACEMENT**
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER/XFMR/BUS	RELAY / RTU STATUS	RELAY/RTU MAKE	RELAY/RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	BATCHAWANA TS						
2	""	NO PROTECTION RELAYS	NO PROTECTION RELAYS	-	-	-	-
3							
4	""	REMOTE TERMINAL UNIT	COMMUNICATES DIRECTLY WITH CENTRAL CONTROL ROOM VIA OPTICAL FIBRE	GE ENERGY SERVICES	iBox Serial	2005	NO REPLACEMENT
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	EXISITNG RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**CLERGUE TS**						
2	""	**115KV CLERGUE LINE NO. 1 (21/28/35MVA)**	A' PROTECTION	SEL	SEL-311L	2008	**GE/L90**
3	""	115KV CLERGUE LINE NO. 1	A' PROTECTION	SEL	SEL-387L	2008	**GE/L90**
4							
5	""	115KV CLERGUE LINE NO. 1	B' PROTECTION	ALSTOM	MiCOM P543	2008	**SEL-411L**
6	""	115KV CLERGUE LINE NO. 1	B' PROTECTION	ALSTOM	MiCOM P543	2008	**SEL-411L**
7							
8	""	**115KV CLERGUE LINE NO. 2**	A' PROTECTION	SEL	SEL-311L	2008	**GE/L90**
9	""	115KV CLERGUE LINE NO. 2	A' PROTECTION	SEL	SEL-387L	2008	**GE/L90**
10							
11	""	115KV CLERGUE LINE NO. 2	B' PROTECTION	ALSTOM	MiCOM P543	2008	**SEL-411L**
12	""	115KV CLERGUE LINE NO. 2	B' PROTECTION	ALSTOM	MiCOM P543	2008	**SEL-411L**
13							
14	""	**115KV COGEN LINE NO.1**	A' PROTECTION	ALSTOM	KCEG112	1993	**GE/F60**
15	""	115KV COGEN LINE NO.1	B' PROTECTION	N/A	N/A	-	**SEL-451-5**
16							
17	""	115KV COGEN LINE NO.1	BKR. FAILURE PROTECTION	ALSTOM	MCTI	1993	**NOT REQUIRED**
18	""	BREAKER FAILURE 50BF	-	-	-	-	
19							
20	""	**115KV COGEN LINE NO.2**	A' PROTECTION	ALSTOM	KCEG112	1993	**GE/F60**
21	""	115KV COGEN LINE NO.2	B' PROTECTION	N/A	N/A	-	**SEL-421-5**
22							
23	""	115KV COGEN LINE NO.2	BKR. FAILURE PROTECTION	ALSTOM	MCTI	1993	**NOT REQUIRED**
24	""	BREAKER FAILURE 50BF					
25							
26							
27							
28							
29							
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

31	CLERGUE TS	FEEDER / XFMR / BUS	RELAY STATUS	RELAY / RTU MAKE	EXISITING RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
32	""	**115KV/12KV XFMR MT1**	A' PROTECTION	SEL	SEL-387E	2008	**GE/T35**
33	""	115KV/12KV XFMR MT1	B' PROTECTION	SEL	SEL-551	2008	**SEL-487E**
34							
35	""	115KV/12KV XFMR MT1	BKR. FAILURE PROTECTION	SEL	SEL-551C	2008	**-**
36	""	BREAKER FAILURE 52-143-50BF	-	-	-		
37							
38	""	**115KV/12KV XFMR MT2**	A' PROTECTION	SEL	SEL-387E	2008	**GE/T35**
39	""	115KV/12KV XFMR MT2	B' PROTECTION	SEL	SEL-551	2008	**SEL-487E**
40							
41	""	**115KV/12KV XFMR MT2**	BKR. FAILURE PROTECTION	SEL	SEL-551C	2008	**-**
42	""	BREAKER FAILURE 52-144-50BF					
43							
44	""	**12KV BUS NO.1 (CB#143)**	A' PROTECTION	AREVA	MiCOM P122	2008	**SEL/SEL-751A**
45	""						
46		**12KV BUS NO.2 (CB#144)**	A' PROTECTION	AREVA	MiCOM P122	2008	**SEL/SEL-751A**
47	""						
48		**12KV BUS TIE (CB#145)**	A' PROTECTION	CANADIAN GENERAL ELECTRIC	IJS (ELECTRO-MECHANICAL)	1980	**GE/MLJ (SYNCHRONISM CHECK)**
49							
50		**12KV PAPER CO. 1 (CB#150)**	A' PROTECTION	ALSTOM	MiCOM P141	2001	**GE/F60**
51							
52		**12KV PAPER CO. 2 (CB#151)**	A' PROTECTION	ALSTOM	MiCOM P141	2001	**GE/F60**
53							
54	""	**12KV PAPER CO. 3 (CB#155)**	A' PROTECTION	ALSTOM	MiCOM P141	2001	**GE/F60**
55							
56	""	**12KV PAPER CO. 4 (CB#154)**	A' PROTECTION	ALSTOM	MiCOM P141	2001	**GE/F60**
57							
59							
60							

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

61	CLERGUE TS	FEEDER / XFMR / BUS	RELAY STATUS	RELAY / RTU MAKE	EXISITNG RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
62	""	**12KV STATION SERVICE 1 (CB#156)**	A' PROTECTION	CANADIAN GENERAL ELECTRIC	IAC (ELECTRO-MECHANICAL)	1980	**SEL-751A**
63							
64	""	**12KV STATION SERVICE 2 (CB#157)**	A' PROTECTION	CANADIAN GENERAL ELECTRIC	IAC (ELECTRO-MECHANICAL)	1980	**SEL-751A**
65							
66							
67							
68							
69							
70							
71							
72							
73							
74							
75	""	**RTU PANEL**	REMOTE TERMINAL UNIT	GE HARRIS	WESDAC D20 ++	-	**SEL-3354**
76							
77	""	**JUNGLEMUX**	FIBRE OPTICAL COMM.	NORTEL	86400 JUNGLEMUX	-	**NO REPLACEMENT**
78							
79							
80							
81							
82							
83							
84							
85							
86							
87							
88							
89							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**ECHO RIVER TS**						
2	""	**230KV/115-34.5KV TXFMR-T1 (25/33/45MVA)**	A' PROTECTION	GE	T60	2009	**GE/T60**
3	""	230KV/115-34.5KV TXFMR-T1	B' PROTECTION	SEL	SEL-487E	2009	**SEL-487E**
4							
5	""	230KV/115-34.5KV TXFMR-T1	BREAKER FAILURE	SEL	SEL-352	2009	**SEL-451-5**
6	""	BREAKER FAILURE	-	-	-		
7							
8	""	**34.5 KV FEEDER NO.1**	A' PROTECTION	GE	F60	2009	**GE/F60**
9	""	34.5 KV FEEDER NO.1	B' PROTECTION	N/A	N/A	-	**-**
10							
11	""	**34.5 KV FEEDER NO.2**	A' PROTECTION	GE	F60	2009	**GE/F60**
12	""	34.5 KV FEEDER NO.2	B' PROTECTION	N/A	N/A	-	**-**
13							
14							
15							
16							
17	""	**SYSTEM COMPUTING PLATFORM**	RTU	SEL	SEL-3351	2009	**SEL-3354**
18							
19	""	**I/O MODULE UNIT 1**	I/O PROCESSOR	SEL	SEL-2410	2009	**SEL-2410**
20	""	**I/O MODULE UNIT 2**	I/O PROCESSOR	SEL	SEL-2410	2009	**SEL-2410**
21							
22	""	**PLC COMMUNICATION**	SCADA/PLC	ABB	ETL640	2009	**ETL640**
23	""						
24	""	**MODEM COMMUNICATION**	BELL LEASED LINES	BELL	-	2009	**-**
25							
26	""						
27							
28							
29	""						

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**GARTSHORE TS**						
2	""	**115KV GARTSHORE L1 - MACKAY TS**	A' PROTECTION	AREVA	MiCOM P442	2006	**GE/D60**
3	""	115KV GARTSHORE L1 - MACKAY TS	B' PROTECTION	SEL	SEL-311C	2006	**SEL-421-5**
4							
5	""	**115KV GARTSHORE L2 - MACKAY TS**	A' PROTECTION	AREVA	MiCOM P442	2006	**GE/D60**
6	""	115KV GARTSHORE L2 - MACKAY TS	B' PROTECTION	SEL	SEL-311C	2006	**SEL-421-5**
7							
8	""	**115KV ANDREWS LINE - ANDREWS GS**	A' PROTECTION	AREVA	MiCOM P442	2006	**GE/D60**
9	""	115KV ANDREWS LINE - ANDREWS GS	B' PROTECTION	SEL	SEL-311C	2006	**SEL-421-5**
10							
11	""	**115KV HOGG LINE - HOGG GS**	A' PROTECTION	AREVA	MiCOM P442	2006	**GE/D60**
12	""	115KV HOGG LINE - HOGG GS	B' PROTECTION	SEL	SEL-311C	2006	**SEL-421-5**
	""	**115KV GARTSHORE L3 - GARTSHORE GS**	A' PROTECTION	SEL	SEL-311L	2006	**GE/L90**
	""	115KV GARTSHORE L3 - GARTSHORE GS	B' PROTECTION	AREVA	MiCOM P543	2006	**SEL-411L**
13							
14	""	**115KV BREAKER FAILURE**					
15	""	115KV BREAKER FAILURE	BF 52-1410	SEL	SEL-352	2006	**NOT REQUIRED**
16	""	115KV BREAKER FAILURE	BF 52-1418	SEL	SEL-352	2006	**NOT REQUIRED**
17	""	115KV BREAKER FAILURE	BF 52-1402	SEL	SEL-352	2006	**NOT REQUIRED**
18	""	115KV BREAKER FAILURE	BF 52-1414	SEL	SEL-352	2006	**NOT REQUIRED**
19	""	115KV BREAKER FAILURE	BF 52-1406	SEL	SEL-352	2006	**NOT REQUIRED**
20							
21							
22							
23	""	**SYSTEM COMPUTING PLATFORM**	REMOTE TERMINAL UNIT	SEL	SEL-3351	-	**SEL-3354**
24							
25	""	**JUNGLEMUX**	FIBRE OPTICAL COMM.	NORTEL	86400 JUNGLEMUX	-	**NO REPLACEMENT**
26							
27							
28							
29							

OneLine Engineering Inc.
63 Church Street, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE
Great Lakes Power Transmission
Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**GOULAIS TS**						
2	""	**NO PROTECTION RELAYS**	NO PROTECTION RELAYS	-	-	-	-
3							
4	""	**REMOTE TERMINAL UNIT 1** CIRCUIT SWITCHER NO. 584	RTU/I/O MODULE	GE HARRIS	SCD	-	**NO REPLACEMENT**
5							
6							
7	""	**REMOTE TERMINAL UNIT 2** CIRCUIT SWITCHER NO. 585	RTU/I/O MODULE	GE HARRIS	SCD	-	**NO REPLACEMENT**
8							
9							
10	""	**REMOTE TERMINAL UNIT 3** MAIN RTU IN SEPERATE BOX	COMMUNICATES DIRECTLY WITH CENTRAL CONTROL ROOM VIA OPTICAL FIBRE	GE HARRIS	SCD	-	**NO REPLACEMENT**
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Rreplacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**HOLLINGSWORTH TS**						
2	""	**115KV HOLLINGSWORTH LINE**	A' PROTECTION	SEL	SEL351A	2005	**GE/D60**
3	""	115KV HOLLINGSWORTH LINE	B' PROTECTION	ALSTOM	MiCOM P141	2005	**SEL-421-5**
4							
5	""	**115KV/11.5 KV XFMR T1 (21/28/35MVA)**	A' PROTECTION	SEL	SEL-387E	2005	**GE/T35**
6	""	115KV/11.5 KV XFMR T1	B' PROTECTION	SEL	SEL-551	2005	**SEL-487E**
7							
8	""	**115KV/44 KV XFMR T2 (25/28MVA)**	A' PROTECTION	ALSTOM	KBCH120	2005	**GE/T35**
9	""	115KV/44 KV XFMR T2	B' PROTECTION	ALSTOM	KCEG140	2005	**SEL-487E**
10							
11	""	**115KV BREAKER FAILURE**					
12	""	115KV BREAKER FAILURE	50BF-52-999	SEL	SEL-551	2005	**-**
13							
14		**11.5KV BUS**	BUS DIFFERENTIAL	AREVA	MFAC	2005	**SEL-587Z**
15							
16							
17							
18							
19							
20	""	**COMMUNICATION PROCESSOR**	COMMUNICATION PROCESSOR	SEL	SEL-2030	-	**SEL-3354**
21							
22	""	**RTU PANEL**	REMOTE TERMINAL UNIT	GE HARRIS	WESDAC D20ME	-	**-**
23				GE HARRIS	I/O MODULES	-	**-**
24							
25	""	**JUNGLEMUX**	FIBRE OPTICAL COMMUNICATION	NORTEL	86400 JUNGLEMUX	-	**NO REPLACEMENT**
26							
27							
28							
29							
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Study-OLER Porject No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**HWY 101 TS**						
2	""	**44KV LIMER LINE**	A' PROTECTION (ELECTRO-MECHANICAL)	ABB	CO-11 HILO	1995	**GE/F60 SEL-351S**
3		PHASE 'A'					
4	""	44KV LIMER LINE	A' PROTECTION (ELECTRO-MECHANICAL)	ABB	CO-11 HILO	1995	
5		PHASE 'B'					
6	""	44KV LIMER LINE	A' PROTECTION (ELECTRO-MECHANICAL)	ABB	CO-11 HILO	1995	
7		PHASE 'C'					
8	""	44KV LIMER LINE	A' PROTECTION (ELECTRO-MECHANICAL)	SEL	CO-11 HILO	1995	
9		1NEUTRAL					
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23	""	**RTU**	REMOTE TERMINAL UNIT	GE HARRIS	SCD	1995	**NO REPLACEMENT**
24							
25	""	**JUNGLEMUX**	FIBRE OPTICAL COMMUNICATION	NORTEL	86400 JUNGLEMUX	1995	**NO REPLACEMENT**
26							
27							
28							
29							
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	MACKAY TS						
2	""	**230KV MACKAY TS - 3RD LINE TS**	A' PROTECTION	AREVA	MiCOM P441	2006	**GE/D90plus**
3	""	230KV MACKAY TS - 3RD LINE TS	B' PROTECTION	SEL	SEL-321	2006	**SEL-421-5**
4							
5	""	**230KV MACKAY TS - WAWA TS**	A' PROTECTION	AREVA	MiCOM P441	2006	**GE/D90plus**
6	""	230KV MACKAY TS - WAWA TS	B' PROTECTION	SEL	SEL-321	2006	**SEL-421-5**
7							
8	""	**230KV/120KV/34.5KV XFMR T2 (120/160/200MVA)**	A' PROTECTION	GE	745	2006	**GE/T60**
9	""	230KV/120KV/34.5KV XFMR T2	B' PROTECTION	SEL	SEL-387E	2006	**SEL-487E**
10							
11	""	**230KV BUS T2H PROTECTION**	A' PROTECTION	AREVA	MCAG	2006	**GE/B90**
12	""	230KV BUS T2H PROTECTION	B' PROTECTION	AREVA	MFAC	2006	**SEL-587Z**
13							
14	""	**230KV BREAKER FAILURE**					
15	""	230KV BREAKER FAILURE	52-682 BKR K24G (3RD LINE TS)	SEL	SEL-352	2006	**SEL-451-5**
16	""	230KV BREAKER FAILURE	52-690 BKR W23K (WAWA TS)	SEL	SEL-352	2006	**SEL-451-5**
17	""	230KV BREAKER FAILURE	52-678 BREAKER TIE	SEL	SEL-352	2006	**SEL-451-5**
18							
19	""	**115KV GARTSHORE TS NO. 1 (RACK 1)**	A' PROTECTION	AREVA	MiCOM P442	2008	**GE/D60**
20	""	115KV GARTSHORE TS NO. 1	B' PROTECTION	SEL	SEL-311C	2008	**SEL-421-5**
21							
22	""	**115KV GARTSHORE TS NO. 2 (RACK 2)**	A' PROTECTION	AREVA	MiCOM P442	2008	**GE/D60**
23	""	115KV GARTSHORE TS NO. 2	B' PROTECTION	SEL	SEL-311C	2008	**SEL-42105**
24							
25	""	**115KV MACKAY NO. 1**	A' PROTECTION	AREVA	MiCOM P543	2008	**GE/L90**
26	""	115KV MACKAY NO. 1	B' PROTECTION	SEL	SEL-311L	2008	**SEL-411L**
27							
28	""	**115KV MACKAY NO. 2**	A' PROTECTION	AREVA	MiCOM P543	2008	**GE/L90**
29	""	115KV MACKAY NO. 2	B' PROTECTION	SEL	SEL-311L	2008	**SEL-411L**
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

31							
32	**MACKAY TS**	**FEEDER / XFMR / BUS**	**RELAY STATUS**	**MAKE**	**TYPE**	**INSTALLATION**	**REPLACED BY**
33	**""**	**115KV SAULT NO.3**	A' PROTECTION	AREVA	MiCOM P442	2008	**GE/D60**
34	""	115KV SAULT NO.3	B' PROTECTION	SEL	SEL-311C	2008	**SEL-421-5**
35							
36	""	**115KV BUS BAR NORTH**	A' PROTECTION	SEL	SEL-587Z	2008	**GE/B90**
37	""	115KV BUS BAR NORTH	B' PROTECTION	AREVA	MiCOM P141	2005 OR 2008??	**SEL-587Z**
38							
39	""	**115KV BUS BAR SOUTH**	A' PROTECTION	SEL	SEL-587Z	2008	**GE/B90**
40	""	115KV BUS BAR SOUTH	B' PROTECTION	AREVA	MiCOM P141	2008	**SEL-587Z**
41							
42	""	**115KV BREAKER FAILURE (RACK 6)**					
43	""	115KV BREAKER FAILURE	A50/52-618 BF	SEL	SEL-352	2006	**-**
44	""	115KV BREAKER FAILURE	A50/52-638 BF	SEL	SEL-352	2006	**-**
45	""	115KV BREAKER FAILURE	A50/52-668 BF	SEL	SEL-352	2006	**-**
46	""	115KV BREAKER FAILURE	A50/52-665 BF	SEL	SEL-352	2006	**-**
47							
48	""	**115KV BREAKER FAILURE (RACK 7)**					
49	""	115KV BREAKER FAILURE	A50/52-615 BF	SEL	SEL-352	2006	**NOT REQUIRED**
50	""	115KV BREAKER FAILURE	A50/52-635 BF	SEL	SEL-352	2006	**NOT REQUIRED**
51	""	115KV BREAKER FAILURE	A50/52-632 BF	SEL	SEL-352	2006	**NOT REQUIRED**
52	""	115KV BREAKER FAILURE	A50/52-662 BF	SEL	SEL-352	2006	**NOT REQUIRED**
53							
54	""	**34.5KV REACTOR R1**	A' PROTECTION	SEL	SEL-351	2006	**GE/F60**
55	""	34.5KV REACTOR R1	B' PROTECTION	N/A	N/A	-	**SEL-351S**
56							
57							
58							
59							
60							
61							
62							
63							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

64							
65							
66	**MACKAY TS**	**FEEDER / XFMR / BUS**	**STATUS**	**MAKE**	**TYPE**	**INSTALLATION**	**REPLACED BY**
67							
68	""	**TELEPROTECTION UNITS / PLC COMM.**					
69	""	**230KV MACKAY TS TO 3RD LINE TS K24G**	TELEPROTECTION UNIT 1	ABB	NSD 570	-	-
70	""	230KV MACKAY TS TO 3RD LINE TS K24G	TELEPROTECTION UNIT 2	ABB	NSD 570	-	-
71	""	230KV MACKAY TS TO 3RD LINE TS K24G	PLC COMMUNICATION	ABB	ETL 580	-	-
72							
73	""	**230KV MACKAY TS TO WAWA TS W23K**	TELEPROTECTION UNIT 1	ABB	NSD 570	-	-
74	""	230KV MACKAY TS TO WAWA TS W23K	TELEPROTECTION UNIT 2	ABB	NSD 570	-	-
75	""	230KV MACKAY TS TO WAWA TS W23K	PLC COMMUNICATION	ABB	ETL 580	-	-
76							
77							
78							
79							
80	""	**RUGGED COMPUTER UNIT 1**	SYSTEM COMPUTING PLATFORM	SEL	SEL-3351	**SEL-3351 IS MASTER**	
81	""	UNIT 1	I/O PROCESSOR	SEL	SEL-2410	-	-
82	""	UNIT 2	I/O PROCESSOR	SEL	SEL-2410	-	-
83							
84	""	**RUGGED COMPUTER UNIT 2**	SYSTEM COMPUTING PLATFORM	SEL	SEL-3351	-	-
85	""	UNIT 3	I/O PROCESSOR	SEL	SEL-2410	-	-
86	""	UNIT 4	I/O PROCESSOR	SEL	SEL-2410	-	-
87							
88	""	**COMMUNICATION PROCESSOR**	INSTALLED ON RACK 3	SEL	SEL-2030	-	-
89							
90	""	D20 RTU 1	REMOTE TERMINAL UNIT	GE HARRIS	WESDAC D20 ME		
91	""	RTU 2	REMOTE TERMINAL UNIT	GE HARRIS		**RTU D20 IS SLAVE**	
92	""	RTU 3	REMOTE TERMINAL UNIT	GE HARRIS	I/O MODULES		
93							
94							
95	""	**JUNGLEMUX**	FIBRE OPTICAL COMMUNICATION	NORTEL	86400 JUNGLEMUX	-	-
96							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENBCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**MAGPIE TS**						
2	""	**115KV HIGH FALLS LINE**	A' PROTECTION	ALSTOM	MiCOM P442	2008	**GE/D60**
3	""	115KV HIGH FALLS LINE	B' PROTECTION	GE ALSTOM	KCEG 140	2008	**SEL-421-5**
4							
5	""	**115KV MISSION LINE**	A' PROTECTION	ALSTOM	MiCOM P442	2008	**GE/D60**
6	""	115KV MISSION LINE	B' PROTECTION	SEL	SEL-311C	2008	**SEL-421-5**
7							
8	""	**115KV STEEPHILL LINE**	A' PROTECTION	ALSTOM	MiCOM P442	2008	**GE/D60**
9	""	115KV STEEPHILL LINE	B' PROTECTION	SEL	SEL-311C	2008	**SEL-421-5**
10							
11	""	**115KV HARRIS LINE**	A' PROTECTION	ALSTOM	MiCOM P442	2008	**GE/D60**
12	""	115KV HARRIS LINE	B' PROTECTION	SEL	SEL-311C	2008	**SEL-421-5**
13							
14	""	**115KV BREAKER FAILURE**					
15	""	115KV BREAKER FAILURE	BREAKER FAILURE 1206	ALSTOM	MiCOM P122	2008	**NOT REQUIRED**
16	""	115KV BREAKER FAILURE	BREAKER FAILURE 1212	ALSTOM	MiCOM P122	2008	**NOT REQUIRED**
17	""	115KV BREAKER FAILURE	BREAKER FAILURE 1218	ALSTOM	MiCOM P122	2008	**NOT REQUIRED**
18	""	115KV BREAKER FAILURE	BREAKER FAILURE 1224	ALSTOM	MiCOM P122	2008	**NOT REQUIRED**
19							
20							
21							
22	""	**RUGGED COMPUTER**	SYSTEM COMPUTING PLATFORM	SEL	SEL-3351	2008	**SEL-3354**
23							
24	""	**UNIT 1**	I/O PROCESSOR	SEL	SEL-2410	2008	**SEL-2440**
25	""	**UNIT 2**	I/O PROCESSOR	SEL	SEL-2410	2008	**SEL-2440**
26							
27	""	**JUNGLEMUX**	FIBRE OPTICAL COMMUNICATION	NORTEL	86400 JUNGLEMUX	-	**NO REPLACEMENT**
28							
29							
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**NORTHERN AV. TS**						
2	""	**115KV/34.5KV TRANSFORMER T1**	A' PROTECTION	SEL	SEL-387E	2004	**GE/T35**
3	""	115KV/34.5KV TRANSFORMER T1	B' PROTECTION	SEL	SEL-551	2004	**SEL487E**
4							
5	""	**34.5KV/12KV TRANSFORMER T2**	B' PROTECTION	SEL	SEL-387E	2004	**GE/T35**
6	""	34.5KV/12KV TRANSFORMER T2	B' PROTECTION	SEL	SEL-551	2004	**SEL487E**
7							
8	""	**DISTRIBUTION RELAY**	A' PROTECTION	SEL	SEL-251D	2004	**SEL-351S**
9	""	F1 PORT	-	-	-	-	**-**
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21	""	**COMMUNICATION PROCESSOR**	COMMUNICATION PROCESSOR	SEL	SEL-2030	2004	**SEL-3354**
22							
23	""	**RTU PANEL**	REMOTE TERMINAL UNIT	GE HARRIS	WESDAC D20 ME	-	**-**
24				GE HARRIS	I/O MODULES	-	**-**
25							
26	""	**JUNGLEMUX**	FIBRE OPTICAL COMMUNICATION	NORTEL	86400 JUNGLEMUX	-	**-**
27							
28							
29							
30							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**STEELTON TS**						
2	""	**115 KV ALGOMA NO. 1**	A' PROTECTION	SEL	SEL-311L	2005	**GE/L90**
3	""	115 KV ALGOMA NO. 1	B' PROTECTION	ALSTOM	MiCOM P521	2005	**SEL-411L**
4	""	115 KV ALGOMA NO. 1	INTERFACE UNIT	ALSTOM	MiCOM P592	2005	**-**
5							
6	""	115 KV ALGOMA NO. 2	A' PROTECTION	ALSTOM	SEL-311L	2005	**GE/L90**
7	""	115 KV ALGOMA NO. 2	B' PROTECTION	SEL	MiCOM P521	2005	**SEL-411L**
8	""	115 KV ALGOMA NO. 2	INTERFACE UNIT	ALSTOM	MiCOM P592	2005	**-**
9							
10	""	**115 KV ALGOMA NO. 3**	A' PROTECTION	SEL	SEL-311L	2005	**GE/L90**
11	""	115 KV ALGOMA NO. 3	B' PROTECTION	ALSTOM	MiCOM P521	2005	**SEL-411L**
12	""	115 KV ALGOMA NO. 3	INTERFACE UNIT	ALSTOM	MiCOM P592	2005	**-**
13							
14	""	**115KV CLERGUE NO. 1**	A' PROTECTION	SEL	SEL-311L	2005	**GE/L90**
15	""	115KV CLERGUE NO. 1	B' PROTECTION	ALSTOM	MiCOM P543	2005	**SEL-411L**
16							
17	""	**115KV CLERGUE NO. 2**	A' PROTECTION	SEL	SEL-311L	2005	**GE/L90**
18	""	115KV CLERGUE NO. 2	B' PROTECTION	ALSTOM	MiCOM P543	2005	**SEL-411L**
19							
20	""	**115KV LEIGH'S BAY**	A' PROTECTION	SEL	SEL-311C	2005	**GE/D60**
21	""	115KV LEIGH'S BAY	B' PROTECTION	ALSTOM	MiCOM P441	2005	**SEL-421-5**
22							
23	""	**115KV BUS NO. 1**	R-Ø	WESTINGHOUSE	671B157A18 (ELECTRO-MECH.)	1993	**GE/B90 (A PROTECTION)**
24	""	115KV BUS NO. 1	Y-Ø	WESTINGHOUSE	671B157A18 (ELECTRO-MECH.)	1993	**SEL-587Z (B PROTECTION)**
25							
26	""	**115KV BUS NO. 2**	B-Ø	GE	BDD (ELECTRO-MECHANICAL)	1993	**GE/B90 ('A' PROTECTION)**
27		115KV BUS NO. 2	Y-Ø	GE	BDD (ELECTRO-MECHANICAL)	1993	**SEL-587Z ('B' PROTECTION)**

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905--688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

28	STEELTON TS	FEEDER / XFMR / BUS	STATUS	MAKE	TYPE	INSTALLATION	REPLACED BY
29	**""**	**115KV BREAKER FAILURE (Panel 1)**					
30	""	115KV BREAKER FAILURE	A50-62BF-228	SEL	SEL-551C	2006	**-**
31	""	115KV BREAKER FAILURE	A50-62BF-235	SEL	SEL-551C	2006	**-**
32	""	115KV BREAKER FAILURE	A50-62BF-248	SEL	SEL-551C	2006	**-**
33	""	115KV BREAKER FAILURE	A50-62BF-214	SEL	SEL-551C	2006	**-**
34	""	115KV BREAKER FAILURE	A50-62BF-217	SEL	SEL-551C	2006	**-**
35							
36	""	**115KV BREAKER FAILURE (Panel 2)**					
37	""	115KV BREAKER FAILURE	B BF 52-222	ALSTOM	MiCOM P122	2006	**-**
38	""	115KV BREAKER FAILURE	B BF 52-232	ALSTOM	MiCOM P122	2006	**SEL-451-5**
39	""	115KV BREAKER FAILURE	B BF 52-242	ALSTOM	MiCOM P122	2006	**-**
40	""	115KV BREAKER FAILURE	B BF 52-245	ALSTOM	MiCOM P122	2006	**-**
41							
42	""	**115KV BREAKER FAILURE (Panel 3)**					
43	""	115KV BREAKER FAILURE (Panel 3)	A50-62BF-225	SEL	SEL-551C	2007	**-**
44	""	115KV BREAKER FAILURE (Panel 3)	A50-62BF-205	SEL	SEL-551C	2007	**-**
45	""	115KV BREAKER FAILURE (Panel 3)	A50-62BF-208	SEL	SEL-551C	2007	**-**
46	""	115KV BREAKER FAILURE (Panel 3)	A50-62BF-211	SEL	SEL-551C	2007	**-**
47							
48							
49							
50							
51							
52	""	RTU PANEL	REMOTE TERMINAL UNIT	GE HARRIS	WESDAC D20 ME	-	**SEL-3354**
53				GE HARRIS	I/O MODULES	-	
54							
55	""	JUNGLEMUX	FIBRE OPTICAL COMMUNICATION	NORTEL	86400 JUNGLEMUX	-	**NO REPLACEMENT**
56							
57							
58							
59							
60							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905--688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**THIRD LINE TS**						
2	""	**230KV LINE K24G (TO MACKAY TS)**	A' PROTECTION	AREVA	MiCOM P441	2005	**GE/D90plus**
3	""	230KV LINE K24G (TO MACKAY TS)	B' PROTECTION	SEL	SEL-321	2005	**SEL-421-5**
4							
5	""	**230KV LINE P21G (TO MISSISAGI TS)**	A' PROTECTION	AREVA	MiCOM P441	2005	**GE/D90plus**
6	""	230KV LINE P21G (TO MISSISAGI TS)	B' PROTECTION	SEL	SEL-321	2005	**SEL-421-5**
7							
8	""	**230KV LINE P22G (TO MISSISAGI TS)**	A' PROTECTION	AREVA	MiCOM P441	2005	**GE/D90plus**
9	""	230KV LINE P22G (TO MISSISAGI TS)	B' PROTECTION	SEL	SEL-321	2005	**SEL-421-5**
10							
11	""	**230KV/115KV/34.5KV XFMR T1 (**	A' PROTECTION	AREVA	MiCOM P633	2005	**GE/T60**
12	""	230KV/115KV/34.5KV XFMR T1	B' PROTECTION	SEL	SEL-387E	2005	**SEL-487E**
13							
14	""	**230KV/115KV/34.5KV XFMR T2**	A' PROTECTION	AREVA	MiCOM P633	2005	**GE/T60**
15	""	230KV/115KV/34.5KV XFMR T2	B' PROTECTION	SEL	SEL-387E	2005	**SEL-487E**
16							
17	""	**230KV BUS T1H**	A' PROTECTION	AREVA	MCAG	2005	**GE/B90**
18	""	230KV BUS T1H	B' PROTECTION	AREVA	MFAC	2005	**SEL-587Z**
19							
20	""	230KV BUS T2H	A' PROTECTION	AREVA	MCAG	2005	**GE/B90**
21	""	**230KV BUS T2H**	B' PROTECTION	AREVA	MFAC	2005	**SEL-587Z**
22							
23	""	**230KV BREAKER FAILURE**					
24	""	230KV BREAKER FAILURE	52-402 BREAKER	SEL	SEL-352	2005	**SEL-451-5**
25	""	230KV BREAKER FAILURE	52-405 BREAKER	SEL	SEL-352	2005	**SEL-451-5**
26	""	230KV BREAKER FAILURE	52-408 BREAKER	SEL	SEL-352	2005	**SEL-451-5**
27	""	230KV BREAKER FAILURE	52-412 BREAKER	SEL	SEL-352	2005	**SEL-451-5**
28	""	230KV BREAKER FAILURE	52-415 BREAKER	SEL	SEL-352	2005	**SEL-451-5**
29							
30	""	**SYNC CHECK/CONTROL**	SYNC CHECK/CONTROL	AREVA	MiCOM P143		**SEL-421-5**
31							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

32	THIRD LINE TS	FEEDER / XFMR / BUS	RELAY / RTU STATUS	MAKE	TYPE	INSTALLATION	REPLACED BY
33	**""**	**115KV ALGOMA NO. 1**	A' PROTECTION	SEL	SEL-311L	2004	**GE/L90**
34	""	115KV ALGOMA NO. 1	B' PROTECTION	ALSTOM	MiCOM P521	2004	**SEL-411L**
35	""	115KV ALGOMA NO. 1	INTERFACE UNIT	ALSTOM	MiCOM P592	2004	**-**
36							
37	""	**115KV ALGOMA NO. 2**	A' PROTECTION	SEL	SEL-311L	2004	**GE/L90**
38	""	115KV ALGOMA NO. 2	B' PROTECTION	ALSTOM	MiCOM P521	2004	**SEL-411L**
39	""	115KV ALGOMA NO. 2	INTERFACE UNIT	ALSTOM	MiCOM P592	2004	**-**
40							
41	""	**115KV ALGOMA NO. 3**	A' PROTECTION	SEL	SEL-311L	2004	**GE/L90**
42	""	115KV ALGOMA NO. 3	B' PROTECTION	ALSTOM	MiCOM P521	2004	**SEL-411L**
43	""	115KV ALGOMA NO. 3	INTERFACE UNIT	ALSTOM	MiCOM P592	2004	
44							
45	""	**115KV NORTHERN AVENUE**	A' PROTECTION	GEC ALSTOM	OPTIMHO	2002	**GE/D60**
46	""	115KV NORTHERN AVENUE	B' PROTECTION	ALSTOM	MiCOM P141	2002	**SEL-421-5**
47							
48	""	**115KV SAULT NO. 3**	A' PROTECTION	GEC ALSTOM	OPTIMHO	2002	**GE/D60**
49	""	115KV SAULT NO. 3	B' PROTECTION	ALSTOM	KCEG140	2002	**SEL-421-5**
50							
51	""	**115KV GL1 SM**	A' PROTECTION	GEC ALSTOM	OPTIMHO	2002	**GE/D60**
52	""	115KV GL1 SM	B' PROTECTION	ALSTOM	MiCOM P141	2002	**SEL-421-5**
53							
54	""	**115KV GL2 SM**	A' PROTECTION	GEC ALSTOM	OPTIMHO	2002	**GE/D60**
55	""	115KV GL2 SM	B' PROTECTION	ALSTOM	MiCOM P141	2002	**SEL-421-5**
56							
57	""	**115KV GL1TA**	A' PROTECTION	GEC ALSTOM	OPTIMHO	2002	**GE/D60**
58	""	115KV GL1TA	B' PROTECTION	ALSTOM	MiCOM P141	2002	**SEL-421-5**
59							
60	""	**115KV GL2TA**	A' PROTECTION	GEC ALSTOM	OPTIMHO	2002	**GE/D60**
61	""	115KV GL2TA	B' PROTECTION	ALSTOM	MiCOM P141	2002	**SEL-421-5**
62							
63							

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

64	THIRD LINE TS	FEEDER / XFMR / BUS	STATUS	MAKE	TYPE	INSTALLATION	REPLACED BY
65	""	**115KV BUS - NORTH BUS**	A' PROTECTION	ALSTOM	MFAC	2004	**GE/B90**
66	""	115KV BUS - NORTH BUS	B' PROTECTION	ALSTOM	MiCOM P141	2004	**SEL-587Z**
67							
68	""	**115KV BUS - SOUTH BUS**	A' PROTECTION	ALSTOM	MFAC	2004	**GE/B90**
69	""	115KV BUS - SOUTH BUS	B' PROTECTION	ALSTOM	MiCOM P141	2004	**SEL-587Z**
70							
71	""	**115KV BREAKER FAILURE**					
72	""	115KV BREAKER FAILURE	BREAKER FAIL 450	ALSTOM	MiCOM P122	2007	-
73	""	115KV BREAKER FAILURE	BREAKER FAIL 495	ALSTOM	MiCOM P122	2002	-
74	""	115KV BREAKER FAILURE	BREAKER FAIL 512	ALSTOM	MiCOM P122	2002	-
75	""	115KV BREAKER FAILURE	BREAKER FAIL 515	ALSTOM	MiCOM P122	2002	-
76							
77	""	**34.5KV CAP. BANK 4**	A' PROTECTION	SEL	SEL-351A	2006	**SEL-487V**
78	""	34.5KV CAP. BANK 4	B' PROTECTION	SEL	SEL-551	2009	**SEL-551**
79							
80	""	**34.5KV CAP. BANK 5**	A' PROTECTION	SEL	SEL-351A	2006	**SEL-487V**
81	""	34.5KV CAP. BANK 5	B' PROTECTION	SEL	SEL-551	2009	**SEL-551**
82							
83	""	**34.5KV BREAKER FAIL 52-532**	CAP. BANK 4	ALSTOM	MiCOM P122	2001	-
84							
85	""	**34.5KV BREAKER FAIL 52-522**	CAP. BANK 5	ALSTOM	MiCOM P122	2001	-
86							
87	""	**FREQUENCY LOAD SHED PANEL 'FLS'**	LOAD SHEDDING	ALSTOM	MiCOM P122	2001	**UNDERFREQUENCY FEATURE COMBINED WITH VLS.**
88							
89	""	**VOLTAGE LOAD SHED PANEL 'VLS'**					
90	""	115KV NORTH BUS	LOAD SHEDDING	ALSTOM	MiCOM P141	2001	**GE/N60**
91	""	115KV SOUTH BUS	LOAD SHEDDING	ALSTOM	MiCOM P141	2001	**GE/N60**
92							
93		**SYNCHRO-CHECK/CONTROL**	SYNCHRO-CHECK	ALSTOM	MiCOM P143	2001	**GE/MLJ**
94							
95							
96							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Project No. 10-003

97	THIRD LINE TS	FEEDER / XFMR / BUS	STATUS	MAKE	TYPE	INSTALLATION	REPLACED BY
98	""	**SYSTEM COMPUTING PLATFORM**	REMOTE TERMINAL UNIT	SEL	SEL-3351	-	**NO REPLACEMENT**
99	""	**RUGGEDCOM**	RUGGEDCOM	RUGGEDSERVER	RS416	-	-
100	""	**COMMUNICATION PROCESSOR**	OMMUNICATIONPROCESSO	SEL	SEL-2030	-	-
101							
102	""	**230KV THIRD LINE TS TO MACKAY TS K24G**	PLC COMMUNICATION	ABB	ETL 580	-	-
103	""	230KV HYDEN K24G 'A' PROTECTION	REMOTE I/O MODULE	SEL	SEL-2506	-	-
104	""	230KV HYDEN K24G 'B' PROTECTION	REMOTE I/O MODULE	SEL	SEL-2506	-	-
105							
106	""	**230KV THIRD LINE TO MISSISAGI TS P21G/P22G**	PLC COMMUNICATION	ABB	ETL 580 (3 Units)	-	-
107	""	230KV THIRD LINE TO MISSISAGI TS P21G/P22G	A' PROTECTION	ABB	NSD 570 (5 Units)	-	-
108							
109	""	**230KV 3RD LINE TS TO ECHO RIVER TS P22G**	PLC COMMUNICATION	ABB	ETL 640	-	-
110	""	230KV 3RD LINE TS TO ECHO RIVER TS P22G	B' PROTECTION	ABB	NSD 570 (3 Units)	-	-
111							
112		**RTU PANELS**					
113	""	RTU 1	REMOTE TERMINAL UNIT	GE HARRIS	WESDAC D20 ME	-	-
114	""	RTU 2	REMOTE TERMINAL UNIT	GE HARRIS	I/O MODULES	-	-
115	""	RTU 3	REMOTE TERMINAL UNIT	GE HARRIS	I/O MODULES	-	-
116							
117	""	**JUNGLEMUX**	RE OPTICAL COMMUNICAT	NORTEL	86400 JUNGLEMUX	-	**NO REPLACEMENT**
118							
119							
120							
121							
122							
123							
124							
125							
126							
127							
128							
129							
130							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Poject No. 10-003

ITEM NO.	TRANSMISSION STATION	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY GE / SEL MAKES
1	**WATSON TS**						
2	""	**115KV HIGH FALLS #1 & XFMR T1**	A' PROTECTION	ALSTOM	KCEG140	1998	**GE/D60**
3	""	115KV HIGH FALLS #1 & XFMR T1	B' PROTECTION	ALSTOM	KCEG140	1998	**SEL-421-5**
4							
5	""	**115KV HIGH FALLS #1 & XFMR T2**	A' PROTECTION	ALSTOM	KCEG140	1998	**GE/D60**
6	""	115KV HIGH FALLS #1 & XFMR T2	B' PROTECTION	N/A	N/A	-	**SEL-421-5**
7							
8	""	**115KV/34.5KV TRANSFORMER T1 (43/60/75MVA)**	A' PROTECTION	ALSTOM	KBCH120	1998	**GE/T35**
9	""	115KV/34.5KV TRANSFORMER T1	B' PROTECTION	ALSTOM	KCEG140	1998	**SEL-587Z**
10							
11	""	**115KV/34.5KV TRANSFORMER T2 (43/60/75MVA)**	A' PROTECTION	ALSTOM	KBCH120	1998	**GE/T35**
12	""	115KV/34.5KV TRANSFORMER T2	B' PROTECTION	ALSTOM	KCEG140	1998	**SEL-587Z**
13							
14	""	**34.5KV WAWA NO. 1**	A' PROTECTION	ALSTOM	KCEG142	2010	**GE/F60**
15	""	34.5KV WAWA NO. 1	B' PROTECTION	ALSTOM	KCEG142	2010	**SEL/351S**
16							
17	""	**34.5KV WAWA NO. 2**	A' PROTECTION	ALSTOM	KCEG140	1998	**GE/F60**
18	""	34.5KV WAWA NO. 2	B' PROTECTION	ALSTOM	KCEG142	1998	**SEL/351S**
19							
20	""	**34.5KV SCOTT NO. 1**	A' PROTECTION	ALSTOM	KCEG142	2010	**GE/F60**
21	""	34.5KV SCOTT NO. 1	B' PROTECTION	ALSTOM	KCEG142	2010	**SEL/351S**
22							
23	""	**34.5KV SCOTT NO. 2**	A' PROTECTION	ALSTOM	KCEG142	2010	**GE/F60**
24	""	34.5KV SCOTT NO. 2	B' PROTECTION	ALSTOM	KCEG140	1998	**SEL/351S**
25							
26	""	**34.5KV McPHAIL NO. 1**	A' PROTECTION	ALSTOM	KCEG140	2010	**GE/F60**
27		34.5KV McPHAIL NO. 1	B' PROTECTION	ALSTOM	KCEG142	2010	**SEL/351S**
28							
29	""	**34.5KV McPHAIL NO. 2**	A' PROTECTION	ALSTOM	KCEG142	1998	**GE/F60**
30		34.5KV McPHAIL NO. 2	B' PROTECTION	ALSTOM	KCEG142	1998	**SEL/351S**
31							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

GLPT RELAYS DATA-QUICK REFERENCE

Great Lakes Power Transmission

Protective Relays Replacement Study-OLE Poject No. 10-003

32	WATSON TS	FEEDER / XFMR / BUS	RELAY / RTU STATUS	RELAY / RTU MAKE	RELAY / RTU TYPE	YEAR OF INSTALLATION	REPLACED BY
33	""	**34.5KV DUNFORD NO. 1**	A' PROTECTION	ALSTOM	MiCOM P141	2002	**GE/F60**
34	""	34.5KV DUNFORD NO. 1	B' PROTECTION	ALSTOM	MiCOM P141	2002	**SEL/351S**
35							
36	""	**34.5KV DUNFORD NO. 2**	A' PROTECTION	ALSTOM	MiCOM P141	2002	**GE/F60**
37	""	34.5KV DUNFORD NO. 2	B' PROTECTION	ALSTOM	MiCOM P141	2002	**SEL/351S**
38							
39	""	**34.5KV BUS 1**	A' PROTECTION	ALSTOM	MFAC	1998	**GE/MIB**
40	""	34.5KV BUS 1	B' PROTECTION	GEC ALSTOM	KCEG140	1998	**SEL/351S**
41							
42	""	**34.5KV BUS 2**	A' PROTECTION	ALSTOM	MFAC	1998	**GE/MIB**
43	""	34.5KV BUS 2	B' PROTECTION	GEC ALSTOM	KCEG140	1998	**SEL/351S**
44							
45	""	**34.5KV BUS TIE BUS 1/BUS 2**	A' PROTECTION	N/A	N/A	1998	**GE/MLJ**
46	""	-	-	-	-	-	
47							
48	""	**BREAKER 1334 SYNCHRONIZER**	AUTO. SYCHRONIZER	BASLER	BE1-25A	1998	**SEL-451**
49							
50							
51							
52							
53							
54	""	**RTUs**					
55	""	RTU 1	REMOTE TERMINAL UNIT	GE HARRIS	WESDAC D20 ME	-	**SEL-3354**
56	""	RTU 2	REMOTE TERMINAL UNIT	GE HARRIS	I/O MODULE	-	**-**
57	""	RTU 3	REMOTE TERMINAL UNIT	GE HARRIS	I/O MODULE	-	**-**
58							
59	""	**JUNGLEMUX**	FIBRE OPTICAL COMM.	NORTEL	86400 JUNGLEMUX	-	**NO REPLACEMENT**
60							
61							
62							
63							

OneLine Engineering Inc.
63 Church Street, Suite 301
St. Catherines, ON L2R 3C4
Phone: 905-688-6857

APPENDIX F

GLPT Existing Relays Data

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN SUTTON/JIM**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**ANDREWS TS**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY PART NUMBER**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**115KV/12KVPOWER TXFMR** 5000KVA/6250KVA								
2	TRIPPING RELAY OIL HIGH TEMPERATURE 49	ALSTOM MVAJ	MVAJ11L1GC0771A	575220N	-	2005	2	6-8 WEEKS	MIDOS SERIES RELAYS
3	TRIPPING RELAY GAS PRESSURE 63	ALSTOM MVAJ	MVAJ11L1GC0780A	326063N	-	2005	2	6-8 WEEKS	
4	TRIPPING RELAY TRANSFER TRIP 94	ALSTOM MVAJ	MVAJ11L1GC0780A	326064N	-	2005	2	6-8 WEEKS	
5									
6	**REMOTE I/O MODULE**	SEL SEL-2505	NOT ACCESSIBLE	NOT ACCESSIBLE	2005	2005	1	3-4 WEEKS	
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN SUTTON/JIM T.**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB HAMMERSTEDT/DON D.**
TRANSMISSION STATION:		**ANJIGAMI T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**115KV HIGH FALLS LINE #1** A' PROTECTION	ALSTOM MiCOM P441	P441311B1A0??A	108202N	2002	2002	2	1-2 BUSINESS DAYS	DISTANCE RELAY
2	115KV HIGH FALLS LINE #1 B' PROTECTION & BF	GE ALSTOM KCEG 140	KCEG14001F15MEC	676056F	1994	1995	4	**OBSOLETE**	A/C OVERCURRENT / DIRECTIONAL O/C RELAY & BF
3	115KV HIGH FALLS LINE #1 TRIPPING RLAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	312402G	1994	2002	3	6-8 WEEKS	MIDOS SERIES RELAYS
4	115KV HIGH FALLS LINE #1 TRIPPING RLAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	312405G	1994	1995	3	6-8 WEEKS	
5									
6	**115KV HIGH FALLS LINE #2** A' PROTECTION	ALSTOM MiCOM P441	P441311B1A0060A	108203N	2002	2002	2	1-2 BUSINESS DAYS	DISTANCE RELAY
7	115KV HIGH FALLS LINE #2 B' PROTECTION & BF	GE ALSTOM KCEG 140	KCEG14001F15MEE	201875J	1994	1995	3	6-8 WEEKS	A/C OVERCURRENT / DIRECTIONAL O/C RELAY & BF
8	115KV HIGH FALLS LINE #2 TRIPPING RLAY 94A	ALSTOM MVAJ	MVAJ11D11GB0771A	201883J	1994	2002	3	6-8 WEEKS	
9	115KV HIGH FALLS LINE #2 TRIPPING RLAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	201886J	1994	1995	3	6-8 WEEKS	
10									
11	**115KV HOLLINGSWORTH LINE** A' PROTECTION	ALSTOM MiCOM P441	P441311B1A0060A	108209N	2002	2009	2	1-2 BUSINESS DAYS	DISTANCE RELAY **REPLACED IN APRIL, 2009**
12	115KV HOLLINGSWORTH LINE B' PROTECTION & BF	GE ALSTOM KCEG 140	KCEG14001F15MEC	720955F	1994	1995	4	**OBSOLETE**	A/C OVERCURRENT / DIRECTIONAL O/C RELAY & BF
13	115KV HOLLINGSWORTH LINE TRIPPING RLAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	312404G	1994	2002	3	6-8 WEEKS	
14	115KV HOLLINGSWORTH LINE TRIPPING RLAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	312397G	1994	1995	3	6-8 WEEKS	
15									
16	**115KV BUS BAR** A' PROTECTION	ALSTOM MFAC	MFAC34F1BA0001A	703188F	1994	1995	2	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
17	115KV BUS BAR TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ101JA0800A	809309/08/03	2003	2003	2	6-8 WEEKS	
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**	**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**	**GLPT PROJECT MANAGERS: DAN/JIM TAIT**
	GLPT ADDENDUM NO. 2010-015-A1004	**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:	**BATCHAWANA T. S.**	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY MODEL #	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
1	NO PROTECTION RELAYS								
2									
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**	**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**	**GLPT PROJECT MANAGERS: DAN SUTTON/JIM T.**
	GLPT ADDENDUM NO. 2010-015-A1004	**ACCOMPANIED BY: BOB H./EUGENE WILLIAMS**
TRANSMISSION STATION:	**CLERGUE TS**	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
1	**115KV CLERGUE LINE NO. 1** A' PROTECTION	SEL SEL-311L	0311L0HCC3254XX	2005056038	2005	2008	1	3-4 WEEKS	A87/87N/21/21N-CL1 LINE CURRENT DIFF. PROTECTION AND AUTOMATION SYSTEM
2	115KV CLERGUE LINE NO. 1 A' PROTECTION	SEL SEL-387L	0387L0HC03X54XX	2005018054	2005	2008	1	3-4 WEEKS	A87/87N-CL1 CURRENT DIFFERENTIAL RELAY
3	115KV CLERGUE LINE NO. 1 B' PROTECTION	AREVA MiCOM P543	P543311A4M0300J	1295787/01/05	2005	2008	2	1-2 DAYS	B87/87N/21/21N-CL1
4	115KV CLERGUE LINE NO. 1 B' PROTECTION	AREVA MiCOM P543	P543311A4M0300J	1295786/01/05	2005	2008	2	1-2 DAYS	B87/87N-CL1
5	115KV CLERGUE LINE NO. 1 TRIPPING RELAY 94B-CL-1	AREVA MVAJ	MVAJ101RA0800A	1428220/06/05	2005	2008	2	6-8 WEEKS	MIDOS SERIES RELAYS
6									
7	**115KV CLERGUE LINE NO. 2** A' PROTECTION	SEL SEL-311L	0311L0HCC3254XX	2005056037	2005	2008	1	3-4 WEEKS	A87/87N/21/21N-CL2 LINE CURRENT DIFF. PROTECTION AND AUTOMATION SYSTEM
8	115KV CLERGUE LINE NO. 2 A' PROTECTION	SEL SEL-387L	0387L0HC03X54XX	2005018053	2005	2008	1	3-4 WEEKS	A87/87N-CL2 CURRENT DIFFERENTIAL RELAY
9	115KV CLERGUE LINE NO. 2 B' PROTECTION	AREVA MiCOM P543	P543311A4M0300J	1295784/01/05	2005	2008	2	1-2 DAYS	B87/87N/21/21N-CL2
10	115KV CLERGUE LINE NO. 2 B' PROTECTION	AREVA MiCOM P543	P543311A4M0300J	1295783/01/05	2005	2008	2	1-2 DAYS	B87/87N-CL2
11	115KV CLERGUE LINE NO. 2 TRIPPING RELAY 94B-CL-2	AREVA MVAJ	MVAJ101RA0800A	1428215/06/05	2005	2008	2	6-8 WEEKS	
12									
13									
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION**		**GLPT MANAGER, ENGG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**		**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
	GLPT ADDENDUM NO. 2010-015-A1004		**ACCOMPANIED BY: BOB/EUGENE WILLAMS**
TRANSMISSION STATION:	**CLERGUE TS**		

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
19	**115KV COGEN LINE NO.1** A' PROTECTION	ALSTOM KCEG112	KCEG11201D51EEB	552080L	1993	1993	3	1-2 BUSINESS DAYS	DIRECTIONAL EARTH FAULT RELAY
20	115KV COGEN LINE NO.1 TRIPPING RELAY 94	ALSTOM MVAA	MVAA11B1BA0781A	802100D	1993	1993	3	6-8 WEEKS	
21	115KV COGEN LINE NO.1 LOCKOUT RELAY 86	ALSTOM MVAJ	MVAJ11D1GB0771A	277659K	1993	1993	3	6-8 WEEKS	MIDOS SERIES RELAYS
22	115KV COGEN LINE NO.1 BREAKER FAILURE 50BF	ALSTOM MCTI	MCTI39D1BD0751F	806668D	1993	1993	3	6-8 WEEKS	
23	115KV COGEN LINE NO.1 LOCKOUT RELAY 86BF	ALSTOM MVAJ	MVAJ13D1GB0780A	809005D	1993	1993	3	6-8 WEEKS	
24	115KV COGEN LINE NO.1 BREAKER FAILURE 62BF	ALSTOM MVTT	MVTT14B1BA0771B	806679D	1993	1993	3	6-8 WEEKS	
25	115KV COGEN LINE NO.1 TRIP CCT. SUPERVISION 27CB	ALSTOM MVAX	MVAX12B1DB0756A	324930E	1993	1993	3	6-8 WEEKS	
26	115KV COGEN LINE NO.1 TRIP CCT. SUPERVISION 27	ALSTOM MVAX	MVAX12B1DB0756A	324933E	1993	1993	3	6-8 WEEKS	
27	115KV COGEN LINE NO.1 LOGIC RELAY	ALSTOM MVGL	MVGL01D1CC6040D	808957D	1993	1993	3	6-8 WEEKS	
28									
29	**115KV COGEN LINE NO.2** A' PROTECTION	ALSTOM KCEG112	KCEG11201L51EEC	458009N	1993	1993	3	1-2 BUSINESS DAYS	DIRECTIONAL EARTH FAULT RELAY
30	115KV COGEN LINE NO.2 TRIPPING RELAY 94	ALSTOM MVAA	MVAA11B1BA0781A	802109D	1993	1993	3	6-8 WEEKS	
31	115KV COGEN LINE NO.2 LOCKOUT RELAY 86	ALSTOM MVAJ	MVAJ11D1GB0771A	277661K	1993	1993	3	6-8 WEEKS	
32	115KV COGEN LINE NO.2 BREAKER FAILURE 50BF	ALSTOM MCTI	MCTI39D1BD0751F	806669D	1993	1993	3	6-8 WEEKS	
33	115KV COGEN LINE NO.2 LOCKOUT RELAY 86BF	ALSTOM MVAJ	MVAJ13D1GB0780A	809000D	1993	1993	3	6-8 WEEKS	
34	115KV COGEN LINE NO.2 BREAKER FAILURE 62BF	ALSTOM MVTT	MVTT14B1BA0771B	806674D	1993	1993	3	6-8 WEEKS	
35	115KV COGEN LINE NO.2 TRIP CCT. SUPERVISION 27BF	ALSTOM MVAX	MVAX12B1DB0756A	324931E	1993	1993	3	6-8 WEEKS	
36	115KV COGEN LINE NO.2 TRIP CCT. SUPERVISION 27CB	ALSTOM MVAX	MVAX12B1DB0756A	324934E	1993	1993	3	6-8 WEEKS	

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	GREAT LAKES POWER TRANSMISSION (GLPT)	GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE	OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY	GLPT PROJECT MANAGERS: DAN SUTTON/JIM T.
	GLPT ADDENDUM NO. 2010-015-A1004	ACCOMPANIED BY: BOB/EUGENE WILLIAMS
TRANSMISSION STATION:	CLERGUE TS	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
37	115KV COGEN LINE NO.2 TRIP CCT. SUPERVISION 27	ALSTOM MVAX	MVAX12B1DB0756A	324932E	1993	1993	3	6-8 WEEKS	
38	115KV COGEN LINE NO.2 LOGIC RELAY	ALSTOM MVGL	MVGL01D1CC6040D	808954D	1993	1993	3	6-8 WEEKS	
39									
40	**115KV/12KV XFMR MT1** 21/28/35 MVA								
41	115KV/12KV XFMR MT1 A' RPOTECTION	SEL SEL-387E	0387E014X5H6X41	2007204215	2007	2008	1	3-4 WEEKS	A87-MT1 CURRENT DIFFERENTIAL AND VOLTAGE PROTECTION RELAY
42	115KV/12KV XFMR MT1 B' RPOTECTION	SEL SEL-551	0551003X5B1X	2007206352	2007	2008	1	3-4 WEEKS	B50/50N/51N-MT1 OVERCURRENT RELAY, RECLOSING RELAY
43	115KV/12KV XFMR MT1 BREAKER FAILURE	SEL SEL-551C	0551C0B5B3X	2007206359	2007	2008	1	3-4 WEEKS	52-143-50BF OVERCURRENT RELAY, RECLOSING RELAY
44	115KV/12KV XFMR MT1 TRIPPING RELAY 94-52-MT1	ALSTOM MVAJ	MVAJ101RA0800A	10025591/08/07	2007	2008	2	6-8 WEEKS	MIDOS SERIES RELAYS
45	115KV/12KV XFMR MT1 TRIPPING RELAY 94B-MT1	ALSTOM MVAJ	MVAJ101RA0800A	10025587/08/07	2007	2008	2	6-8 WEEKS	
46	115KV/12KV XFMR MT1 TRIPPING RELAY A63/49 MT1	ALSTOM MVAJ	MVAJ101RA0800A	10025589/08/07	2007	2008	2	6-8 WEEKS	
47	115KV/12KV XFMR MT1 TRIPPING RELAY A71X	ALSTOM MVAJ	MVAJ101RA0802A	2390365/04/08	2008	2008	2	6-8 WEEKS	
48									
49	**115KV/12KV XFMR MT2** 21/28/35 MVA								
50	115KV/12KV XFMR MT2 A' RPOTECTION	SEL SEL-387E	0387E014X5H6X41	2007204216	2007	2008	1	3-4 WEEKS	A87-MT2 CURRENT DIFFERENTIAL AND VOLTAGE PROTECTION RELAY
51	115KV/12KV XFMR MT2 B' RPOTECTION	SEL SEL-551	0551003X5B1X	2007206352	2007	2008	1	3-4 WEEKS	B50/50N/51N-MT2 OVERCURRENT RELAY, RECLOSING RELAY
52	115KV/12KV XFMR MT2 BREAKER FAILURE	SEL SEL-551C	0551C0B5B3X	2007206360	2007	2008	1	3-4 WEEKS	52-144-50BF OVERCURRENT RELAY, RECLOSING RELAY
53	115KV/12KV XFMR MT2 TRIPPING RELAY 94-52-MT2	ALSTOM MVAJ	MVAJ101RA0800A	10025592/08/07	2007	2008	2	6-8 WEEKS	
54	115KV/12KV XFMR MT2 TRIPPING RELAY 94B-MT2	ALSTOM MVAJ	MVAJ101RA0800A	10025588/08/07	2007	2008	2	6-8 WEEKS	

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	GREAT LAKES POWER TRANSMISSION (GLPT)	GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:	OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY	GLPT PROJECT MANAGERS: DAN SUTTON/JIM T.
	GLPT ADDENDUM NO. 2010-015-A1004	ACCOMPANIED BY: BOB H./EUGENE WILLIAMS
TRANSMISSION STATION:	CLERGUE TS	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
55	115KV/12KV XFMR MT2 TRIPPING RELAY A63/49 MT2	ALSTOM MVAJ	MVAJ101RA0800A	10025590/08/07	2007	2008	2	6-8 WEEKS	MIDOS SERIES RELAYS
56	115KV/12KV XFMR MT2 TRIPPING RELAY A71X	ALSTOM MVAJ	MVAJ101RA0802A	2390364/04/08	2008	2008	2	6-8 WEEKS	
57									
58	**12KV BUS TIE 145** SYNCHRONISM CHECK RELAY	CANADIAN GE IJS	IJS52D1A	N/A	1980	1980	3	15-50 BUSINESS DAYS	ELECTRO-MECHANICAL RELAY
59									
60									
61									
62									
63									
64									
65									
66									
67									
68									
69									
70									
71									
72									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGER: DAN SUTTON**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB HAMMERSTEDT/DON**
TRANSMISSION STATION:		**ECHO RIVER TS**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY PART NUMBER**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**230KV/115-34.5KV TXFMR-T1** 25/33/45MVA (LTC ±10%)								**COMMISSIONED IN 2009**
2	230KV/115-34.5KV TXFMR-T1 A' PROTECTION	GE T60	T60E00HCF8GHM8HP4CU4C4CW6U	MBHC09000075	2009	2009	1	20 BUSINESS DAYS	TRANSFORMER MANAGEMENT RELAY
3	230KV/115-34.5KV TXFMR-T1 B' PROTECTION	SEL SEL-487E	0487E0X61111XXB4H674XXX	2009181306	2009	2009	1	3-4 WEEKS	PROTECTION AUTOMATION CONTROL
4	230KV/115-34.5KV TXFMR-T1 TRIPPNG RELAY	ALSTOM MVAJ	MVAJ11L1GB0771A	8194488M	2009	2009	1	6-8 WEEKS	TRANSFORMER PROTECTIVE DEVICES TRIP
5	230KV/115-34.5KV TXFMR-T1 BREAKER FAILURE	SEL SEL-352	035221425H6X4X1	2009187273	2009	2009	1	3-4 WEEKS	BREAKER FAILURE RELAY, CLOSING CONTROL RELAY, DATA PROCESSOR RELAY
6									
7	**34.5 KV FEEDER NO.1** A' PROTECTION	GE F60	F60E00HCHF8FH4CMXXP4CU6UWXX	AAHC09001218	2009	2009	1	20 BUSINESS DAYS	FEEDER MANAGERMENT RELAY
8									
9	**34.5 KV FEEDER NO.2** A' PROTECTION	GE F60	F60E00HCHF8FH4CMXXP4CU6UWXX	MAHC09000072	2009	2009	1	20 BUSINESS DAYS	FEEDER MANAGERMENT RELAY
10									
11	**SYSTEM COMPUTING PLATFORM**	SEL SEL-3351	33514578XH000460A00	2009187214	2009	2009	1	3-4 WEEKS	SYSTEM COMPUTING PLATFORM
12									
13	**I/O PROCESSOR** A' MONITOR SEL2410	SEL SEL-2410	NOT ACCESSIBLE	NOT ACCESSIBLE	2009	2009	1	3-4 WEEKS	I/O PROCESSOR
14									
15	**I/O PROCESSOR** B' MONITOR SEL2410	SEL SEL-2410	NOT ACCESSIBLE	NOT ACCESSIBLE	2009	2009	1	3-4 WEEKS	I/O PROCESSOR
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN/JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**GARTSHORE TS**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY PART NUMBER**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**115KV GARTSHORE L1 - MACKAY TS** A' PROTECTION	AREVA MiCOM P442	P442318B4M0300J	1935967/10/06	2006	2006	2	1-2 BUSINESS DAYS	
2	115KV GARTSHORE L1 - MACKAY TS B' PROTECTION	SEL SEL-311C	0311C01H2425421	2006135098	2006	2006	1	3-4 WEEKS	
3	115KV GARTSHORE L1 - MACKAY TS BREAKER FAILURE BF 52-1410	SEL SEL-352	035221425H2X4X1	2006135197	2006	2006	1	3-4 WEEKS	
4									
5	**115KV GARTSHORE L2 - MACKAY TS** A' PROTECTION	AREVA MiCOM P442	P442318B4M0300J	1935966/10/06	2006	2006	2	1-2 BUSINESS DAYS	
6	115KV GARTSHORE L2 - MACKAY TS B' PROTECTION	SEL SEL-311C	0311C01H2425421	2006135097	2006	20006	1	3-4 WEEKS	
7	115KV GARTSHORE L2 - MACKAY TS BREAKER FAILURE BF 52-1418	SEL SEL-352	035221425H2X4X1	2006135195	2006	2006	1	3-4 WEEKS	
8									
9	**115KV GARTSHORE L3 - GARTSHORE GS** A' PROTECTION	SEL SEL-311L	0311L0HCC4254X1	200613205	2006	2006	1	3-4 WEEKS	
10	115KV GARTSHORE L3 - GARTSHORE GS B' PROTECTION	AREVA MiCOM P543	P543318A4M0520K	1936567/10/06	2006	2006	2	1-2 BUSINESS DAYS	
11	115KV GARTSHORE L3 - GARTSHORE GS BREAKER FAILURE BF 52-1402	SEL SEL-352	035221425H2X4X1	2006135196	2006	2006	1	3-4 WEEKS	
12									
13	**SYSTEM COMPUTING PLATFORM** RACK 3	SEL SEL-3351	33513576XH0404EGB(	2006345076	2006	2006	1	3-4 WEEKS	
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**	**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**	**GLPT PROJECT MANAGERS: DAN SUTTON/KIM**
	GLPT ADDENDUM NO. 2010-015-A1004	**ACCOMPANIED BY: BOB HAMMERSTEDT/DON**
TRANSMISSION STATION:	**GARTSHORE TS**	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
19	**115KV ANDREWS LINE - ANDREWS GS** A' PROTECTION	AREVA MiCOM P442	P442311B1M0300J	1935964/060/06	2006	2006	2	1-2 BUSINESS DAYS	
20	115KV ANDREWS LINE - ANDREWS GS B' PROTECTION	SEL SEL-311C	0311C01H2425421	2006191114	2006	2006	1	3-4 WEEKS	
21	115KV ANDREWS LINE - ANDREWS GS BREAKER FAILURE BF 52-1414	SEL SEL-352	035221425H2X4X1	2006135198	2006	2006	1	3-4 WEEKS	
22									
23	**115KV HOGG LINE - HOGG GS** A' PROTECTION	AREVA MiCOM P442	P442318B4M0300J	1935965/10/06	2006	2006	2	1-2 BUSINESS DAYS	
24	115KV HOGG LINE - HOGG GS B' PROTECTION	SEL SEL-311C	0311C01H2425421	2006135096	2006	2006	1	3-4 WEEKS	
25	115KV HOGG LINE - HOGG GS BREAKER FAILURE BF 52-1406	SEL SEL-352	035221425H2X4X1	2006135199	2006	2006	1	3-4 WEEKS	
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									
36									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S//JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB/DON DOWDING**
TRANSMISSION STATION:		**GOULAIS T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	NO PROTECTION RELAYS								
2									
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**	**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**	**GLPT PROJECT MANAGERS: DAN SUTTON/JIM T.**
	GLPT ADDENDUM NO. 2010-015-A1004	**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:	**HOLLINGWORTH TS**	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
1	**115KV HOLLINGSWORTH LINE** A' PROTECTION	SEL SEL351A	0351A00H24554X1	2005194088	2005	2005	1	3-4 WEEKS	A67-50-51-50N-51N-L1 DISTRIBUTION PROTECTION SYSTEM
2	115KV HOLLINGSWORTH LINE B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0100B	535353N	2000	2005	2	BUSINESS DAYS	67-50-51-50N-51N-L1
3	115KV HOLLINGSWORTH LINE TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11L1GB0771A	575223N	2000	2005	2	6-8 WEEKS	20/05/2010
4									
5									
6									
7	**115KV/11.5 KV XFMR T1** 21/28/35 MVA								
8	115KV/11.5 KV XFMR T1 A' PROTECTION	SEL SEL-387E	0387E014X56X41	2005194089	2005	2005	1	3-4 WEEKS	CURRENT DIFF. AND VOLTAGE RELAY A8-51-51N-T1
9	115KV/11.5 KV XFMR T1 B' PROTECTION	SEL SEL-551	0551003X5B1X	2005193248	2005	2005	1	3-4 WEEKS	B50-51-50N-51N-T1 OVERCURRENT RELAY, RECLOSING RELAY
10	115KV/11.5 KV XFMR T1 TRIPPING RELAY A63/49A-T1	AREVA MVAJ	MVAJ101RA0800A	1468177/08/05	2005	2005	2	6-8 WEEKS	
11	115KV/11.5 KV XFMR T1 TRIPPING RELAY 94B-T1	AREVA MVAJ	MVAJ101RA0800A	1468176/08/05	2005	2005	2	6-8 WEEKS	
12	115KV/11.5 KV XFMR T1 TRIP CCT. SUPERVISION 74T	AREVA MVAX	MVAX31S1CD0754A	1464216/07/05	2005	2005	2	6-8 WEEKS	
13									
14	**115KV BREAKER FAILURE** 50BF-52-999	SEL SEL-551	0551003X5B1X	2005193247	2005	2005	1	3-4 WEEKS	OVERCURRENT RELAY, RECLOSING RELAY
15	115KV BREAKER FAILURE TRIPPING RELAY 94B-52-999	AREVA MVAJ	MVAJ101RA0800A	1468175/08/05	2005	2005	2	6-8 WEEKS	
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**HOLINGSWORTH TS**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY PART NUMBER**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
19	**115KV/44 KV XFMR T2** A' PROTECTION	ALSTOM KBCH120	KBCH12001H15MEI	552075L	1999	2005	3	1-2 BUSINESS DAYS	
20	115KV/44 KV XFMR T2 B' PROTECTION	ALSTOM KCEG140	KCEG14001F15MEC	720947F	1997	2005	4	OBSOLETE	
21	115KV/44 KV XFMR T2 TRIPPING RELAY 94A-T2	ALSTOM MVAJ	MVAJ11L1GB0771A	575225N	2005	2005	2	6-8 WEEKS	MIDOS SERIES RELAYS
22	115KV/44 KV XFMR T2 TRIPPING RELAY 94B-L2	ALSTOM MVAJ	MVAJ11L1GB0771A	575222N	2005	2005	2	6-8 WEEKS	
23	115KV/44 KV XFMR T2 TRIP CCT. SUPERVISION 74T	ALSTOM MVAX	MVAX31S1CD0754A	1464215/07/05	2005	2005	2	6-8 WEEKS	
24									
25	**11.5KV BUS 1 PROTECTION** A' PROTECTION	ALSTOM MFAC	MFAC34F1BA0001A	49678G	1995	2005	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
26	11.5KV BUS 1 PROTECTION B' PROTECTION	N/A	-	-	-	-	-	-	
27									
28									
29									
30									
31									
32									
33									
34									
35									
36									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**								**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**								**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
	GLPT ADDENDUM NO. 2010-015-A1004								**ACCOMPANIED BY: BOB HAMMERSTEDT/DON D.**
TRANSMISSION STATION:	**HWY. 101 TS**								**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY PART NUMBER**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**44KV LIMER LINE** A' PROTECTION - PHASE A	ABB CO-11 HILO	265C047A07	NOT AVAILABLE	1995	1995	3	6-8 WEEKS	OVERCURRENT RELAY ELECTROMECHANICAL OVERCURRENT RELAY
2	44KV LIMER LINE A' PROTECTION - PHASE B	ABB CO-11 HILO	265C047A07	NOT AVAILABLE	1995	1995	3	6-8 WEEKS	OVERCURRENT RELAY ELECTROMECHANICAL OVERCURRENT RELAY
3	44KV LIMER LINE A' PROTECTION - PHASE C	ABB CO-11 HILO	265C047A07	NOT AVAILABLE	1995	1995	3	6-8 WEEKS	OVERCURRENT RELAY ELECTROMECHANICAL OVERCURRENT RELAY
4	44KV LIMER LINE A' PROTECTION - NEUTRAL	ABB CO-11 HILO	265C047A05	NOT AVAILABLE	1995	1995	3	6-8 WEEKS	OVERCURRENT RELAY ELECTROMECHANICAL OVERCURRENT RELAY
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	GREAT LAKES POWER TRANSMISISON (GLPT)								GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:	OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY								GLPT PROJECT MANAGERS: DAN S./JIM TAIT
	GLPT ADDENDUM NO. 2010-015-A1004								ACCOMPANIED BY: BOB H./DON DOWDING
TRANSMISSION STATION:	MACKAY TS								GLPT FAILURE REPORT/COMMENTS
ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	
1	**230KV MACKAY TS - 3RD LINE TS** A' PROTECTION	AREVA MiCOM P441	P441311A1M0300J	1334203.03.05	2005	2006	2	1-2 BUSINESS DAYS	
2	230KV MACKAY TS - 3RD LINE TS B' PROTECTION	SEL SEL-321	321124256HGB134	2005019048	2005	2006	1	3-4 WEEKS	PHASE & GRND DIST. RELAY, DIR. O/C, FAULT LOCATOR
3									
4	230KV MACKAY TS - 3RD LINE TS COMMUNICATION TX11 / RX31	ABB NSD 570	1KHW001179R1002	HE512126		2006	1		TELEPROTECTION EQUIPMENT
5	230KV MACKAY TS - 3RD LINE TS COMMUNICATION TX13 / RX33	ABB NSD 570	1KHW001179R1002	HE511885		2006	1		TELEPROTECTION EQUIPMENT
6									
7									
8	**230KV MACKAY TS - WAWA TS** A' PROTECTION	AREVA MiCOM P441	P441311A1M0300J	1334199.03.05	2005	2006	2	1-2 BUSINESS DAYS	
9	230KV MACKAY TS - WAWA TS B' PROTECTION	SEL SEL-321	321124256HGB134	2005019050	2005	2006	1	3-4 WEEKS	PHASE & GRND DIST. RELAY, DIR. O/C, FAULT LOCATOR
10									
11	230KV MACKAY TS - WAWA TS COMMUNICATION	ABB NSD 570	1KHW001179R1002	HE512125		2006	1		TELEPROTECTION EQUIPMENT
12	230KV MACKAY TS - WAWA TS COMMUNICATION	ABB NSD 570	1KHW001179R1002	HE511883		2006	1		TELEPROTECTION EQUIPMENT
13									
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**MACKAY TS**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY PART NUMBER**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
19	**230KV/120KV/34.5KV XFMR T2** 120/160/200 MVA	AREVA ATOC-NF	INST. MANUAL: 111.353	111.353/U	2004	2006	-	-	MINERAL OIL COOLING SYSTEM: ONAN/ONAF/ONAF
20	230KV/120KV/34.5KV XFMR T2 A' PROTECTION	GE 745	745-W3-P5-G5-HI-E	N/A	2006	2006	1	20 BUSINESS DAYS	TRANSFORMER MANAGEMENT RELAY
21	230KV/120KV/34.5KV XFMR T2 B' PROTECTION	SEL SEL-387E	0387E014X5H6X4X	2005019054	2005	2006	1	3-4 WEEKS	CURRENT DIFFERENTIAL AND VOLTAGE RELAY
22									
23	**34.5KV REACTOR R1** A' PROTECTION	SEL SEL-351	035151H45546XX	2005019056	2005	2006	1	3-4 WEEKS	DIRECTIONAL OVERCURRENT, RECLOSING, FAULT LOCATOR
24									
25	**230KV BUS T2H PROTECTION** A' PROTECTION	AREVA MCAG	MCAG34VCDF0270A	1331665/03/05	2005	2006	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
26	230KV BUS T2H PROTECTION B' PROTECTION	AREVA MFAC	MFAC34V1BB0001A	1334981/03/05	2005	2006	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
27									
28									
29									
30									
31									
32									
33									
34									
35									
36									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB/DON DOWDING**
TRANSMISSION STATION:		**MACKAY TS**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY PART NUMBER**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
37	**230KV BREAKER FAILURE** RACK 2								
38	230KV BREAKER FAILURE 52-678 BREAKER TIE	SEL SEL-352	035222425H154X1	2005019065	2005	2006	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
39	230KV BREAKER FAILURE 52-682 BKR K24G (3RD LINE TS)	SEL SEL-352	035222425H154X1	2005019059	2005	2006	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
40									
41	**230KV BREAKER FAILURE** RACK 3								
42	230KV BREAKER FAILURE 52-690 BKR W23K (WAWA TS)	SEL SEL-352	035222425H154X1	2005019060	2005	2006	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
43									
44	**COMMUNICATION PROCESSOR** RACK 3	SEL SEL-2030	203000X344XXXX	2005019067	2005	2006	3		COMMUNICATION PROCESSOR, NETWORK CARD SUPPORT
45									
46									
47									
48									
49									
50									
51									
52									
53									
54									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**		**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**		**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
	GLPT ADDENDUM NO. 2010-015-A1004		**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:	**MACKAY TS**		

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
55	**115KV GARTSHORE TS NO. 1** A' PROTECTION	AREVA MiCOM P442	P442318B4M0350J	2781283/10/07	2007	2008	2	1-2 BUSINESS DAYS	A50/50N/21P/21N/50LT/25
56	115KV GARTSHORE TS NO. 1 B' PROTECTION	SEL SEL-311C	0311C01H2425461	2007276194	2007	2008	1	3-4 WEEKS	PROTECTION AND AUTOMATION SYSTEM
57	115KV GARTSHORE TS NO. 1 **SEL MASTER**	SEL **SEL-3351**	33514578XH0404EHF00	2007277172	2007	2008	1	3-4 WEEKS	SYSTEM COMPUTING PLATFORM
58	115KV GARTSHORE TS NO. 1 UNIT 1	SEL SEL-2410	241001A3A3A3A3XXX	2007276104	2007	2008	1	3-4 WEEKS	I/O PROCESSOR
59	115KV GARTSHORE TS NO. 1 UNIT 2	SEL SEL-2410	241001A3A3A3A3XXX	UNACCESSIBLE	2007	2008	1	3-4 WEEKS	I/O PROCESSOR
60									
61	**115KV GARTSHORE TS NO. 2** A' PROTECTION	AREVA MiCOM P442	P442318B4M0350J	2781280/10/07	2007	2008	2	1-2 BUSINESS DAYS	A50/50N/21P/21N/50LT/25
62	115KV GARTSHORE TS NO. 2 B' PROTECTION	SEL SEL-311C	0311C01H2425461	2007276196	2007	2008	1	3-4 WEEKS	PROTECTION AND AUTOMATION SYSTEM
62	115KV GARTSHORE TS NO. 2 **SEL MASTER**	SEL **SEL-3351**	33514578XH0404EHF00	2007277171	2007	2008	1	3-4 WEEKS	SYSTEM COMPUTING PLATFORM
64	115KV GARTSHORE TS NO. 2 UNIT 1	SEL SEL-2410	241001A3A3A3A3XXX	UNACCESSIBLE	2007	2008	1	3-4 WEEKS	I/O PROCESSOR
65	115KV GARTSHORE TS NO. 2 UNIT 2	SEL SEL-2410	241001A3A3A3A3XXX	UNACCESSIBLE	2007	2008	1	3-4 WEEKS	I/O PROCESSOR
66									
67	**115KV MACKAY NO. 1** A' PROTECTION	AREVA MiCOM P543	P543318A4M520K	2778538/10/07	2007	2008	2	1-2 BUSINESS DAYS	A87/87N/21P/21G/25
68	115KV MACKAY NO. 1 B' PROTECTION	SEL SEL-311L	0311L0HCC4254X1XX	2007276204	2007	2008	1	3-4 WEEKS	LINE CURRENT DIFF. PROTECTION AND AUTOMATION SYST
69	115KV MACKAY NO. 1	SEL SEL-2410	241001A3A3A3A3XXX	2007276106	2007	2008	1	3-4 WEEKS	I/O PROCESSOR
70									
71	**115KV MACKAY NO. 2** A' PROTECTION	AREVA MiCOM P543	P543318A4M520K	2778539/10/07	2007	2008	2	1-2 BUSINESS DAYS	A87/87N/21P/21G/25
72	115KV MACKAY NO. 2 B' PROTECTION	SEL SEL-311L	0311L0HCC4254X1XX	2007334095	2007	2008	1	3-4 WEEKS	LINE CURRENT DIFF. PROTECTION AND AUTOMATION SYST

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**								**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**								**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
	GLPT ADDENDUM NO. 2010-015-A1004								**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:	**MACKAY TS**								**GLPT FAILURE REPORT/COMMENTS**

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
73	**115KV SAULT NO.3** A' PROTECTION	AREVA MiCOM P442	P442318B4M0350J	2781281/10/07	2007	2008	2	1-2 BUSINESS DAYS	A50/50N/21P/21N/50LT/25
74	115KV SAULT NO.3 B' PROTECTION	SEL SEL-311C	0311C0H2425461	2007276193	2007	2008	1	3-4 WEEKS	PROTECTION AND AUTOMATION SYSTEM
75									
76	**115KV BUS BAR NORTH** A' PROTECTION	SEL SEL-587Z	0587Z0X625H12XX	2007277342	2007	2008	1	3-4 WEEKS	HIGH IMPEDANCE DIFFERENTIAL RELAY
77	115KV BUS BAR NORTH B' PROTECTION	AREVA MiCOM P141	P141318A4M0360J	2783075/10/07	2007	2008	2	1-2 BUSINESS DAYS	HIGH IMPEDANCE DIFFERENTIAL RELAY
78	115KV BUS BAR NORTH A86-1	AREVA MVAJ	MVAJ103RA0804A	10029984/10/07	2007	2008	1	6-8 WEEKS	
79	115KV BUS BAR NORTH A86-2	AREVA MVAJ	MVAJ103RA0804A	10029988/10/07	2007	2008	1	6-8 WEEKS	
80	115KV BUS BAR NORTH B86-1	AREVA MVAJ	MVAJ103RA0804A	10029985/10/07	2007	2008	1	6-8 WEEKS	
81	115KV BUS BAR NORTH B86-2	AREVA MVAJ	MVAJ103RA0804A	10029989/10/07	2007	2008	1	6-8 WEEKS	
82									
83	**115KV BUS BAR SOUTH** A' PROTECTION	SEL SEL-587Z	0587Z0X625H12XX	2007277341	2007	2008	1	3-4 WEEKS	HIGH IMPEDANCE DIFFERENTIAL RELAY
84	115KV BUS BAR SOUTH B' PROTECTION	AREVA MiCOM P141	P141318A4M0360J	2783076/10/07	2007	2008	2	1-2 BUSINESS DAYS	
85	115KV BUS BAR SOUTH A86	AREVA MVAJ	MVAJ103RA0804A	10029987/10/07	2007	2008	1	6-8 WEEKS	
86	115KV BUS BAR SOUTH B86	AREVA MVAJ	MVAJ103RA0804A	10029986/10/07	2007	2008	1	6-8 WEEKS	
87									
88									
89									
90									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	GREAT LAKES POWER TRANSMISSION (GLPT)	GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:	OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY	GLPT PROJECT MANAGERS: DAN S./JIM TAIT
	GLPT ADDENDUM NO. 2010-015-A1004	ACCOMPANIED BY: BOB H./DON DOWDING
TRANSMISSION STATION:	MACKAY TS	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY PART NUMBER	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
91	**115KV BREAKER FAILURE** RACK 6								
92	115KV BREAKER FAILURE **A50/52-618 BF**	SEL SEL-352	035221425H6X4X1	2007276338	2007	2008	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
93	115KV BREAKER FAILURE **A50/52-638 BF**	SEL SEL-352	035221425H6X4X1	2007276345	2007	2008	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
94	115KV BREAKER FAILURE **A50/52-668 BF**	SEL SEL-352	035221425H6X4X1	2007276341	2007	2008	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
95	115KV BREAKER FAILURE **A50/52-665 BF**	SEL SEL-352	035221425H6X4X1	2007276340	2007	2008	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
96									
97	**115KV BREAKER FAILURE** RACK 7								
98	115KV BREAKER FAILURE **A50/52-615 BF**	SEL SEL-352	035221425H6X4X1	2007276344	2007	2008	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
99	115KV BREAKER FAILURE **A50/52-635 BF**	SEL SEL-352	035221425H6X4X1	2007276342	2007	2008	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
100	115KV BREAKER FAILURE **A50/52-632 BF**	SEL SEL-352	035221425H6X4X1	2007276339	2007	2008	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
101	115KV BREAKER FAILURE **A50/52-662 BF**	SEL SEL-352	035221425H6X4X1	2007276343	2007	2008	1	3-4 WEEKS	BREAKER FAILURE, CLOSING CONTROL, DATA RECORDER
102									
103									
104									
105									
106									
107									
108									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**MAGPIE TS**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY PART NUMBER**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**115KV HIGH FALLS LINE NO. 1** A' PROTECTION	AREVA MiCOM P442	P442318B4M0350J	2781282/10/07	2007	2008	2	1-2 BUSINESS DAYS	
2	115KV HIGH FALLS LINE NO. 1 B' PROTECTION	GE ALSTOM KCEG140	KCEG14001F15MEC	720652F	1994	2008	4	OBSOLETE	
3	115KV HIGH FALLS LINE NO. 1 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ1101GB0771A	320615G	-	2008	3	6-8 WEEKS	
4									
5	**115KV MISSION LINE** A' PROTECTION	AREVA MiCOM P442	P442318B4M0300J	2822416/12/07	2007	2008	2	1-2 BUSINESS DAYS	
6	115KV MISSION LINE B' PROTECTION	SEL SEL-311C	0311C01H2425461	2007284091	2007	2008	1	3-4 WEEKS	
7									
8	**115KV STEEPHILL LINE** A' PROTECTION	AREVA MiCOM P442	P442318B4M0300J	2822415/12/07	2007	2008	2	1-2 BUSINESS DAYS	
9	115KV STEEPHILL LINE B' PROTECTION	SEL SEL-311C	0311C01H2425461	2007284092	2007	2008	1	3-4 WEEKS	
10									
11	**115KV HARRIS LINE** A' PROTECTION	AREVA MiCOM P442	P442318B4M0400K	3050140/03/08	2008	2008	2		
12	115KV HARRIS LINE B' PROTECTION	SEL SEL-311C	0311C01H242561	2007284093	2007	2008	1	3-4 WEEKS	
13									
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**NORTHERN AV. T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**115KV/34.5KV TRANSFORMER T1 20/26.7MVA**								
2	115KV/34.5KV TRANSFORMER T1 A' PROTECTION	SEL SEL-387E	0387EO13X5H6X4X	2004281126	2004	2004	1	3-4 WEEKS	CURRENT DIFFERENTIAL AND VOLTAGE PROTECTION RELAY
3	115KV/34.5KV TRANSFORMER T1 B' PROTECTION	SEL SEL-551	0551003X5X1X	2004282020	2004	2004	1	3-4 WEEKS	OVERCURRENT RELAY/RECLOSING RELAY
4	115KV/34.5KV TRANSFORMER T1 TRIPPING RELAY B94A-T1	ALSTOM MVAJ	MVAJ101JA0800A	1200142/10/04	2004	2004	1	6-8 WEEKS	
5	115KV/34.5KV TRANSFORMER T1 TRIPPING RELAY A63/49TA-T1	ALSTOM MVAJ	MVAJ101JA0800A	1200146/10/04	2004	2004	1	6-8 WEEKS	
6	115KV/34.5KV TRANSFORMER T1 TRIP CCT. SUPERVISION 74T-52-385	ALSTOM MVAX	MVAX31K1DE0754A	1199052/10/04	2004	2004	1	6-8 WEEKS	
7									
8	**34.5KV/12KV TRANSFORMER T2 3750/5000KVA**								
9	34.5KV/12KV TRANSFORMER T2 A' PROTECTION	SEL SEL-387E	0387E013X5H6X4X	2004281125	2004	2004	1	3-4 WEEKS	CURRENT DIFFERENTIAL AND VOLTAGE PROTECTION RELAY
10	34.5KV/12KV TRANSFORMER T2 B' PROTECTION	SEL SEL-551	0551003X5X1X	2004282021	2004	2004	1	3-4 WEEKS	OVERCURRENT RELAY/RECLOSING RELAY
11	34.5KV/12KV TRANSFORMER T2 TRIPPIMG RELAY A63-49TA-T2	ALSTOM MVAJ	MVAJ101JA0800A	1200143/10/04	2004	2004	1	6-8 WEEKS	
12	34.5KV/12KV TRANSFORMER T2 TRIPPIMG RELAY 94A-F1	ALSTOM MVAJ	MVAJ101JA0800A	1200144/10/04	2004	2004	1	6-8 WEEKS	
13	34.5KV/12KV TRANSFORMER T2 TRIPPIMG RELAY B94A-T2	ALSTOM MVAJ	MVAJ101JA0800A	1200145/10/04	2004	2004	1	6-8 WEEKS	
14	34.5KV/12KV TRANSFORMER T2 TRIP CCT. SUPERVISION 74T-52-382	ALSTOM MVAX	MVAX31K1DE0754A	1199051/10/04	2004	2004	1	6-8 WEEKS	
15									
16	**COMMUNICATIONS PROCESSOR**	SEL SEL-2030	203000X30XXXXX	2004281127	2004	2004	1	3-4 WEEKS	
17									
18	**DISTRIBUTION RELAY F1 PORT**	SEL SEL-251D	251D00-4356UHGB	2004282022	2004	2004	1	3-4 WEEKS	

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**	**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**	**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
	GLPT ADDENDUM NO. 2010-015-A1004	**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:	**STEELTON T. S.**	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY MODEL #	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
1	**115 KV ALGOMA NO. 1** A' PROTECTION	SEL SEL-311L	0311L0HCA3254XX	2003335188	2003	2005	1	3-4 WEEKS	LINE CURRENT DIFFERENTIAL AND AUTOMATION SYSTEM
2	115 KV ALGOMA NO. 1 B' PROTECTION	ALSTOM MiCOM P521	16889/001	5103537		2005	2	1-2 BUSINESS DAYS	LINE CURRENT DIFFERENTIAL PROTECTION
3	115 KV ALGOMA NO. 1 INTERFACE UNIT	ALSTOM MiCOM P592	P592601A0A0000A	941360/12/03	2003	2005	2	1-2 BUSINESS DAYS	INTERFACE UNIT FOR COMMUNICATIONS
4	115 KV ALGOMA NO. 1 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997350/02/04	2004	2005	1	6-8 WEEKS	
5	115 KV ALGOMA NO. 1 LOAD REJECTION RELAY	SEL SEL-451		2005202038	2005	2005	1		PROTECTION AUTOMATION CONTROL
6	115 KV ALGOMA NO. 1 TRIPPING RELAY LB-2	ALSTOM MVAJ	MVAJ101RA800A	170547/03/06	2006	2005	1	6-8 WEEKS	
7	115 KV ALGOMA NO. 1 TRIPPING RELAY LB-6	ALSTOM MVAJ	MVAJ101RA800A	1428219/06/05	2005	2005	1	6-8 WEEKS	
8	115 KV ALGOMA NO. 1 COMMUNICATIONS PROCESSOR	SEL SEL-2030	203000X344XXXX	2005019069	2005	2005	1		COMMUNICATIONS PROCESSOR NETWORK CARD SUPPORT UNIT
9									
10	**115 KV ALGOMA NO. 2** A' PROTECTION	SEL SEL-311L	0311L0HCA3254XX	2003335182	2003	2005	1	3-4 WEEKS	LINE CURRENT DIFFERENTIAL AND AUTOMATION SYSTEM
11	115 KV ALGOMA NO. 2 B' PROTECTION	ALSTOM MiCOM P521	16889/001	5103541		2005	2	1-2 BUSINESS DAYS	
12	115 KV ALGOMA NO. 2 INTERFACE UNIT	ALSTOM MiCOM P592	P592601A0A0000A	941364/12/03	2003	2005	2	1-2 BUSINESS DAYS	INTERFACE UNIT FOR COMMUNICATIONS
13	115 KV ALGOMA NO. 2 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997349/02/04	2004	2005	3	6-8 WEEKS	
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY:BOB H./DON DOWDING**
TRANSMISSION STATION:		**STEELTON T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
19	**115 KV ALGOMA NO. 3** A' PROTECTION	SEL SEL-311L	0311L0HCA3254XX	2003335181	2003	2005	1	3-4 WEEKS	LINE CURRENT DIFFERENTIAL AND AUTOMATION SYSTEM
20	115 KV ALGOMA NO. 3 B' PROTECTION	ALSTOM MiCOM P521	16889/001	5103539		2005	2	1-2 BUSINESS DAYS	LINE CURRENT DIFFERENTIAL PROTECTION
21	115 KV ALGOMA NO. 3 INTERFACE UNIT	ALSTOM MiCOM P592	P592601A0A0000A	941363/12/03	2003	2005	2	1-2 BUSINESS DAYS	INTERFACE UNIT FOR COMMUNICATIONS
22	115 KV ALGOMA NO. 3 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997348/02/04	2004	2005	3	6-8 WEEKS	
23									
24	**115KV CLERGUE NO. 1** A' PROTECTION	SEL SEL-311L	0311L0HCA3254XX	2003335184	2003	2005	1	3-4 WEEKS	LINE CURRENT DIFFERENTIAL AND AUTOMATION SYSTEM
25	115KV CLERGUE NO. 1 B' PROTECTION	ALSTOM MiCOM P543	P543311A4M0300J	1295785/01/05	2005	2005	2	1-2 BUSINESS DAYS	LINE CURRENT DIFFERENTIAL PROTECTION
26	115KV CLERGUE NO. 1 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101RA0800A	1428217/06/05	2005	2005	3	6-8 WEEKS	
27									
28	**115KV CLERGUE NO. 2** A' PROTECTION	SEL SEL-311L	0311L0HCA3254XX	2003335186	2003	2005	1	3-4 WEEKS	LINE CURRENT DIFFERENTIAL AND AUTOMATION SYSTEM
29	115KV CLERGUE NO. 2 B' PROTECTION	ALSTOM MiCOM P543	P543311A4M0300J	1295788/01/05	2005	2005	2	1-2 BUSINESS DAYS	LINE CURRENT DIFFERENTIAL PROTECTION
30	115KV CLERGUE NO. 2 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101RA0800A	1428218/06/05		2005	3	6-8 WEEKS	
31									
32	**115KV LEIGH'S BAY** A' PROTECTION	SEL SEL-311C	0311C00H2354XX	2005229235	2005	2005	1	3-4 WEEKS	PROTECTION AND AUTOMATION SYSTEM
33	115KV LEIGH'S BAY B' PROTECTION	ALSTOM MiCOM P441	P441311BM0300J	1505538/09/05	2005	2005	2	1-2 BUSINESS DAYS	DISTANCE RELAY
34	115KV LEIGH'S BAY TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	354509L	-	2005	3	6-8 WEEKS	
35									
36									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	GREAT LAKES POWER TRANSMISSION (GLPT)								GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:	OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY								GLPT PROJECT MANAGERS: DAN S./JIM TAIT
	GLPT ADDENDUM NO. 2010-015-A1004								ACCOMPANIED BY: BOB H./DON DOWDING
TRANSMISSION STATION:	STEELTON T. S.								GLPT FAILURE REPORT/COMMENTS
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
37	**115KV BUS NO. 1** R-Ø	WESTINGHOUSE N/A	671B157A18	N/A	1993	1993	3	15-50 BUSINESS DAYS	DIFFERENTIAL RELAY (ELECTROMECHANICAL)
38	115KV BUS NO. 1 Y-Ø	WESTINGHOUSE N/A	671B157A18	N/A	1993	1993	3	15-50 BUSINESS DAYS	DIFFERENTIAL RELAY (ELECTROMECHANICAL)
39	115KV BUS NO. 1 TRIPPING RELAY	ALSTOM/AREVA MVAJ	MVAJ13D1GB0771A	720861F	-	1993	3	6-8 WEEKS	
40	115KV BUS NO. 1 TRIP CCT. SUPERVISION RELAY	ALSTOM/AREVA MVAX	MVAX12B1DB0756A	324935E	-	1993	3	6-8 WEEKS	
41									
42	**115KV BUS NO. 2** B-Ø	GE BDD	12BDD19B1A	N/A	1993	1993	3	15-50 BUSINESS DAYS	DIFFERENTIAL RELAY (ELECTROMECHANICAL)
43	115KV BUS NO. 2 Y-Ø	GE BDD	12BDD19B1A	N/A	1993	1993	3	15-50 BUSINESS DAYS	DIFFERENTIAL RELAY (ELECTROMECHANICAL)
44	115KV BUS NO. 2 TRIPPING RELAY	ALSTOM/AREVA MVAJ	MVAJ13D1GB0771A	809011D	-	1993	3	6-8 WEEKS	
45	115KV BUS NO. 2 TRIP CCT. SUPERVISION RELAY	ALSTOM/AREVA MVAX	MVAX12B1DB0756A	806693D	-	1993	3	6-8 WEEKS	
46									
47									
48									
49									
50									
51									
52									
53									
54									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGER: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**STEELTON T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
55	**115KV BREAKER FAILURE PANEL #1**								
56	115KV BF PANEL #1 **A50-62BF-228**	SEL SEL-551C	0551C0BX5B1X	2005341175	2005	2006	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
57	115KV BF PANEL #1 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	354514L	-	2006	3	6-8 WEEKS	
58	115KV BF PANEL #1 **A50-62BF-235**	SEL SEL-551C	0551C0BX5B1X	2005341178	2005	2006	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
59	115KV BF PANEL #1 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	354513L	-	2006	3	6-8 WEEKS	
60	115KV BF PANEL #1 **A50-62BF-248**	SEL SEL-551C	0551C0BX5B1X	2005341171	2005	2006	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
61	115KV BF PANEL #1 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	622111H	-	2006	3	6-8 WEEKS	
62	115KV BF PANEL #1 **A50-62BF-214**	SEL SEL-551C	0551C0BX5B1X	2005341179	2005	2006	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
63	115KV BF PANEL #1 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	622114H	-	2006	3	6-8 WEEKS	
64	115KV BF PANEL #1 **A50-62BF-217**	SEL SEL-551C	0551C0BX5B1X	2005341172	2005	2006	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
65	115KV BF PANEL #1 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	622116H	-	2006	3	6-8 WEEKS	
66									
67									
68									
69									
70									
71									
72									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		GREAT LAKES POWER TRANSMISSION (GLPT)							GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:		OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY							GLPT PROJECT MANAGERS: DAN S./JIM TAIT
		GLPT ADDENDUM NO. 2010-015-A1004							ACCOMPANIED BY: BOB H./DON DOWDING
TRANSMISSION STATION:		STEELTON T. S.							GLPT FAILURE REPORT/COMMENTS
ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY MODEL #	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	
73	**115KV BREAKER FAILURE PANEL # 2**								
74	115KV BF PANEL #2 **B BF 52-222**	ALSTOM MiCOM P122	17526/001	804154	2004	2006	2	1-2 BUSINESS DAYS	OVERCURRENT RELAY / RECLOSING RELAY
75	115KV BF PANEL #2 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997343/02/04	2004	2006	3	6-8 WEEKS	
76	115KV BF PANEL #2 **B BF 52-232**	ALSTOM MiCOM P122	17526/001	804152	2004	2006	2	1-2 BUSINESS DAYS	OVERCURRENT RELAY / RECLOSING RELAY
77	115KV BF PANEL #2 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997343/02/04	2004	2006	3	6-8 WEEKS	
78	115KV BF PANEL #2 **B BF 52-242**	ALSTOM MiCOM P122	17526/001	804149	2004	2006	2	1-2 BUSINESS DAYS	OVERCURRENT RELAY / RECLOSING RELAY
79	115KV BF PANEL #2 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997343/02/04	2004	2006	3	6-8 WEEKS	
80	115KV BF PANEL #2 **B BF 52-245**	ALSTOM MiCOM P122	17526/001	804153	2004	2006	2	1-2 BUSINESS DAYS	OVERCURRENT RELAY / RECLOSING RELAY
81	115KV BF PANEL #2 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997343/02/04	2004	2006	3	6-8 WEEKS	
82									
83									
84									
85									
86									
87									
88									
89									
90									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**STEELTON T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
91	**115KV BREAKER FAILURE PANEL #3**								
92	115KV BF PANEL #3 A50-62BF-225	SEL SEL-551C	0551C0BX5B1X	2005341177	2005	2007	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
93	115KV BF PANEL #3 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	622117H	-	2007	3	6-8 WEEKS	
94	115KV BF PANEL #3 A50-62BF-205	SEL SEL-551C	0551C0BX5B1X	2005341173	2005	2007	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
95	115KV BF PANEL #3 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	622113H	-	2007	3	6-8 WEEKS	
96	115KV BF PANEL #3 A50-62BF-208	SEL SEL-551C	0551C0BX5B1X	2005341174	2005	2007	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
97	115KV BF PANEL #3 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	327730L	-	2007	3	6-8 WEEKS	
98	115KV BF PANEL #3 A50-62BF-211	SEL SEL-551C	0551C0BX5B1X	2005341176	2005	2007	1	3-4 WEEKS	OVERCURRENT RELAY / RECLOSING RELAY
99	115KV BF PANEL #3 TRIPPING RELAY	ALSTOM MVAJ	MVAJ11D1GB0771A	354510L	-	2007	3	6-8 WEEKS	
100									
101									
102									
103									
104									
105									
106									
107									
108									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./EUGENE WILLIAMS**
TRANSMISSION STATION:		**THIRD LINE T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**230KV LINE K24G (TO MACKAY TS)** A' PROTECTION	AREVA P441	P441311AM0300J	1334200.03.05	2005	2005	2	1-2 BUSINESS DAYS	
2	230KV LINE K24G (TO MACKAY TS) B' PROTECTION	SEL SEL-321	321124256HGB134	2005019049	2005	2005	1	3-4 WEEKS	PHASE & GRND. DISTANCE RELAY, DIR. O/C, FAULT LOCATOR
3									
4	**230KV LINE P21G (TO MISSISAGI TS)** A' PROTECTION	AREVA P441	P441311AM0300J	1334201.03.05	2005	2005	2	1-2 BUSINESS DAYS	
5	230KV LINE P21G (TO MISSISAGI TS) B' PROTECTION	SEL SEL-321	321124256HGB134	2005019046	2005	2005	1	3-4 WEEKS	PHASE & GRND. DISTANCE RELAY, DIR. O/C, FAULT LOCATOR
6									
7	**230KV LINE P22G (TO MISSISAGI TS)** A' PROTECTION	AREVA P441	P441311AM0300J	1334198.03.05	2005	2005	2	1-2 BUSINESS DAYS	
8	230KV LINE P22G (TO MISSISAGI TS) B' PROTECTION	SEL SEL-321	321124256HGB134	2005019047	2005	2005	1	3-4 WEEKS	PHASE & GRND. DISTANCE RELAY, DIR. O/C, FAULT LOCATOR
9									
10	**230KV BUS T1H** A' PROTECTION	AREVA MCAG	MCAG34VCDF0270A	1331664/03/05	2005	2005	3	SEE NOTE	**NOTE**: NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
11	230KV BUS T1H B' PROTECTION	AREVA MFAC	MFAC34V1BB0001A	1334982/03/05	2005	2005	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
12									
13	**230KV BUS T2H** A' PROTECTION	AREVA MCAG	MCAG34VCDF0270A	1331667/03/05	2005	2005	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
14	230KV BUS T2H B' PROTECTION	AREVA MFAC	MFAC34V1BB0001A	1334984/03/05	2005	2005	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		GREAT LAKES POWER TRANSMISSION (GLPT)							GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:		OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY							GLPT PROJECT MANAGERS: DAN S./JIM TAIT
		GLPT ADDENDUM NO. 2010-015-A1004							ACCOMPANIED BY: BOB H./EUGENE WILLIAMS
TRANSMISSION STATION:		THIRD LINE T. S.							GLPT FAILURE REPORT/COMMENTS
ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY MODEL #	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	
19	**230KV BREAKER FAILURE** 52-402 BREAKER	SEL SEL-352	035222425H154X1	2005019066	2005	2005	1	3-4 WEEKS	BREKER FAILURE, CLOSING CONTROL, DATA RECORDER
20	**230KV BREAKER FAILURE** 52-405 BREAKER	SEL SEL-352	035222425H154X1	2005019066	2005	2005	1	3-4 WEEKS	BREKER FAILURE, CLOSING CONTROL, DATA RECORDER
21	**230KV BREAKER FAILURE** 52-408 BREAKER	SEL SEL-352	035222425H154X1	2005019061	2005	2005	1	3-4 WEEKS	BREKER FAILURE, CLOSING CONTROL, DATA RECORDER
22	**230KV BREAKER FAILURE** 52-412 BREAKER	SEL SEL-352	035222425H154X1	2005019066	2005	2005	1	3-4 WEEKS	BREKER FAILURE, CLOSING CONTROL, DATA RECORDER
23	**230KV BREAKER FAILURE** 52-415 BREAKER	SEL SEL-352	035222425H154X1	2005019063	2005	2005	1	3-4 WEEKS	BREKER FAILURE, CLOSING CONTROL, DATA RECORDER
24									
25	**COMMUNICATION PROCESSOR**	SEL SEL-2030	203000X344XXXX	2005019068	2005	2005	-	3-4 WEEKS	COMMUNICATION PROCESSOR, NETWORK CARD SUPPORT
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									
36									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		GREAT LAKES POWER TRANSMISSION (GLPT)							GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:		OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY							GLPT PROJECT MANAGERS: DAN S./JIM TAIT
		GLPT ADDENDUM NO. 2010-015-A1004							ACCOMPANIED BY: BOB H./EUGENE WILLIAMS
TRANSMISSION STATION:		THIRD LINE T. S.							GLPT FAILURE REPORT/COMMENTS
ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY MODEL #	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	
37	**115KV ALGOMA NO. 1** A' PROTECTION	SEL SEL-311L	0311L0HCA3254XX	2003335185	2003	2004	1	3-4 WEEKS	LINE CURRENT DIFF. PROTECTION AND AUTOMATION SYSTE
38	115KV ALGOMA NO. 1 B' PROTECTION	ALSTOM MiCOM P521	P521A0CF111	5103538		2004	2	1-2 BUSINESS DAYS	LINE CURRENT DIFFERENTIAL PROTECTION
39	115KV ALGOMA NO. 1 INTERFACE UNIT	ALSTOM MiCOM P592	P592601A0A0000A	297189N		2004	2	1-2 BUSINESS DAYS	INTERFACE UNIT
40	115KV ALGOMA NO. 1 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997346/02/04	2004	2004	3	6-8 WEEKS	
41									
42	**115KV ALGOMA NO. 2** A' PROTECTION	SEL SEL-311L	0311L0HCA3254XX	2003335180	2003	2004	1	3-4 WEEKS	LINE CURRENT DIFF. PROTECTION AND AUTOMATION SYSTE
43	115KV ALGOMA NO. 2 B' PROTECTION	ALSTOM MiCOM P-521	P521A0CF111	5103536		2004	2	1-2 BUSINESS DAYS	LINE CURRENT DIFFERENTIAL PROTECTION
44	115KV ALGOMA NO. 2 INTERFACE UNIT	ALSTOM MiCOM P592	P592601A0A0000A	941362/12/03	2003	2004	2	1-2 BUSINESS DAYS	INTERFACE UNIT
45	115KV ALGOMA NO. 2 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997347/02/04	2004	2004	3	6-8 WEEKS	
46									
47	**115KV ALGOMA NO. 3** A' PROTECTION	SEL SEL-311L	0311L0HCA3254XX	2003336015	2003	2004	1	3-4 WEEKS	LINE CURRENT DIFF. PROTECTION AND AUTOMATION SYSTE
48	115KV ALGOMA NO. 3 B' PROTECTION	ALSTOM MiCOM P-521	P521A0CF111	5103540		2004	2	1-2 BUSINESS DAYS	LINE CURRENT DIFFERENTIAL PROTECTION
49	115KV ALGOMA NO. 3 INTERFACE UNIT	ALSTOM MiCOM P592	P592601A0A0000A	941361/12/03	2003	2004	2	1-2 BUSINESS DAYS	INTERFACE UNIT
50	115KV ALGOMA NO. 3 TRIPPING RELAY	ALSTOM MVAJ	MVAJ101JA0800A	997351/02/04	2004	2004	3	6-8 WEEKS	
51									
52									
53									
54									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./EUGENE WILIAMS**
TRANSMISSION STATION:		**THIRD LINE T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
55	**115KV NORTHERN AVENUE** A' PROTECTION	GEC ALSTOM OPTIMHO	LFZP131S50005E	815786H	1996	2002	4	**OBSOLETE**	
56	115KV NORTHERN AVENUE B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	232387N	2001	2002	2	1-2 BUSINESS DAYS	B67/67N/51/51N-N.AVE DIRECTIONAL OVERCURRENT RELAY
57	115KV NORTHERN AVENUE TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11L1GB0771A	329133N	-	2002	3	6-8 WEEKS	
58	115KV NORTHERN AVENUE TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11L1GB0771A	368398N	-	2002	3	6-8 WEEKS	
59									
60	**115KV SAULT NO. 3** A' PROTECTION	GEC ALSTOM OPTIMHO	LFZP131S50005DZ	318337G	1995	2002	4	**OBSOLETE**	
61	115KV SAULT NO. 3 B' PROTECTION	ALSTOM KCEG140	KCEG1401F15MEE	073104J	1997	2002	4	**OBSOLETE**	67/67N/51/51N DIRECTIONAL OVERCURRENT RELAY
62	115KV SAULT NO. 3 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	320609G	-	2002	3	6-8 WEEKS	
63	115KV SAULT NO. 3 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	320614G	-	2002	3	6-8 WEEKS	
64									
65	**115KV GL1 SM** A' PROTECTION	GEC ALSTOM OPTIMHO	LFZP131S50005D	31834G	1995	2002	4	**OBSOLETE**	A21L-GL1SM
66	115KV GL1 SM B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	582992M	2000	2002	2	1-2 BUSINESS DAYS	
67	115KV GL1 SM TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11L1GB0771A	368402N	-	2002	3	6-8 WEEKS	
68	115KV GL1 SM TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11L1GB0771A	575221N	-	2002	3	6-8 WEEKS	
69									
70	**115KV GL2 SM** A' PROTECTION	GEC ALSTOM OPTIMHO	LFZP131S50005D	315131G	1995	2002	4	**OBSOLETE**	A21L-GL2SM
71	115KV GL2 SM B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	232378N	2001	2002	2	1-2 BUSINESS DAYS	
72	115KV GL2 SM TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11L1GB0771A	575209N	-	2002	3	6-8 WEEKS	

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3 OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./EUGENE WILLIAMS**
TRANSMISSION STATION:		**THIRD LINE T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
73	115KV GL2 SM (CONTD.) TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11L1GB0771A	575208N	-	2002	3	6-8 WEEKS	
74									
75	**115KV GL1TA** A' PROTECTION	GEC ALSTOM OPTIMOH	LFZP131S50005E	815785H	1996	2002	4	**OBSOLETE**	A21-GLITA
76	115KV GL1TA B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	232385N	2001	2002	2	1-2 BUSINESS DAYS	
77	115KV GL1TA TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11L1GB0771A	329137N	-	2002	3	6-8 WEEKS	
78	115KV GL1TA TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11L1GB0771A	786198M	-	2002	3	6-8 WEEKS	
79									
80	**115KV GL2TA** A' PROTECTION	GEC ALSTOM OPTIMOH	LFZP131S50005E	815784H	1996	2002	4	**OBSOLETE**	A21-GL2TA
81	115KV GL2TA B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	232384N	2001	2002	2	1-2 BUSINESS DAYS	
82	115KV GL2TA TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11L1GB0771A	786199M	-	2002	3	6-8 WEEKS	
83	115KV GL2TA TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11L1GB0771A	786196M	-	2002	3	6-8 WEEKS	
84									
85	**230KV/115KV/34.5KV XFMR T1** 150/200/250 MVA								
86	230KV/115KV/34.5KV XFMR T1 A' PROTECTION	AREVA MiCOM P633	P6338481140NU00E09	02624620/07/07	2007	2007	2	1-2 BUSINESS DAYS	
87	230KV/115KV/34.5KV XFMR T1 B' PROTECTION	SEL SEL-387E	0387E014X5H6X4X	2005019055	2005	2007	1	3-4 WEEKS	CURRENT DIFFERENTIAL AND VOLTAGE PROTECTION RELAY
88	230KV/115KV/34.5KV XFMR T1 TRIPPING RELAY 94A1	AREVA MVAJ	MVAJ101RA0800A	10021223/07/07	2007	2007	3	6-8 WEEKS	
89	230KV/115KV/34.5KV XFMR T1 TRIPPING RELAY 94A2	AREVA MVAJ	MVAJ101RA0800A	10021222/07/07	2007	2007	3	6-8 WEEKS	
90									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./EUGENE WILLIAMS**
TRANSMISSION STATION:		**THIRD LINE T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
91	**230KV/115KV/34.5KV XFMR T2** 150/200/250 MVA								
92	230KV/115KV/34.5KV XFMR T2 A' PROTECTION	AREVA MiCOM P633	P633-84891140-305-406-610-714-921-800	300:35155	2008	2008	2	1-2 BUSINESS DAYS	
93	230KV/115KV/34.5KV XFMR T2 B' PROTECTION	SEL SEL-387E	0387E014X5H6X4X	20055019052	2005	2008	1	3-4 WEEKS	
94	**SYNC CHECK/CONTROL**	AREVA MiCOM P143	P143318L4M0410J	30035154	2008	2008	2	1-2 BUSINESS DAYS	
95	230KV/115KV/34.5KV XFMR T2 TRIPPING RELAY 94A1	AREVA MVAJ	MVAJ101RA0800A	10050483/08/08	2008	2008	3	6-8 WEEKS	
96	230KV/115KV/34.5KV XFMR T2 TRIPPING RELAY 94A2	AREVA MVAJ	MVAJ101RA0800A	10050482/08/08	2008	2008	3	6-8 WEEKS	
97									
98	**115KV BREAKER FAILURE 450** BREAKER FAIL 450	ALSTOM MiCOM P122	P122A00M211	702451	2002	2007	2	1-2 BUSINESS DAYS	
99	115KV BREAKER FAILURE 450 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11L1GB0771A	329131N	-	2007	3	6-8 WEEKS	
100	115KV BREAKER FAILURE 450 TRIP CCT. MONITORING 94BF	ALSTOM MVAX	MVAX31S1DC0754A	1414557/06/05	2005	2007	3	6-8 WEEKS	
101	**115KV BREAKER FAILURE 495** BREAKER FAIL 495	ALSTOM MiCOM P122	P122A00M211	702450	-	2002	2	1-2 BUSINESS DAYS	
102	115KV BREAKER FAILURE 495 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11L1GB0771A	326080N	-	2002	3	6-8 WEEKS	
103	**115KV BREAKER FAILURE 512** BREAKER FAIL 512	ALSTOM MiCOM P122	P122A00M211	702453	2002	2002	2	1-2 BUSINESS DAYS	
104	115KV BREAKER FAILURE 512 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11L1GB0771A	326079N	-	2002	3	6-8 WEEKS	
105	115KV BREAKER FAILURE 512 TRIPPING RELAY 94BFB	AREVA MVAJ	MVAJ11T1GB0771A	1485433/08/05	2005	2005	3	6-8 WEEKS	**REPLACED**
106	**115KV BREAKER FAILURE 515** BREAKER FAIL 515	ALSTOM MiCOM P122	P122A00M211	702444	2002	2002	2	1-2 BUSINESS DAYS	
107	115KV BREAKER FAILURE 515 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11L1GB0771A	368403N	-	2002	3	6-8 WEEKS	
108									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	GREAT LAKES POWER TRANSMISSION (GLPT)	GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:	OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY	GLPT PROJECT MANAGERS: DAN S./JIM TAIT
	GLPT ADDENDUM NO. 2010-015-A1004	ACCOMPANIED BY: BOB H./EUGENE WILLIAMS
TRANSMISSION STATION:	THIRD LINE T. S.	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY MODEL #	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
109	**115KV BUS - NORTH BUS** A' PROTECTION	ALSTOM MFAC	MFAC34N1BB3001A	1086478/06/04	2004	2004	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
110	115KV BUS - NORTH BUS B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0020A	552066L		2004	2	1-2 BUSINESS DAYS	OVERCURRENT RELAY, RECLOSING RELAY
111	115KV BUS - NORTH BUS TRIPPING RELAY A94B (FOR A)	ALSTOM MVAJ	MVAJ13L1GB0771A	1102367/06/04	2004	2004	3	6-8 WEEKS	
112	115KV BUS - NORTH BUS TRIPPING RELAY A94A (FOR B)	ALSTOM MVAJ	MVAJ13D1GB0771A	809002D	-	2004	3	6-8 WEEKS	
113	115KV BUS - NORTH BUS TRIPPING RELAY A94B (FOR B)	ALSTOM MVAJ	MVAJ11D1GB0771A	552100L	-	2004	3	6-8 WEEKS	
114									
115	**115KV BUS - SOUTH BUS** A' PROTECTION	ALSTOM MFAC	MFAC34N1BB3001A	1086479/06/04	2004	2004	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
116	115KV BUS - SOUTH BUS B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0020A	552070L		2004	2	1-2 BUSINESS DAYS	
117	115KV BUS - SOUTH BUS TRIPPING RELAY A94B (FOR A)	ALSTOM MVAJ	MVAJ101JA0800A	1050168/06/04	2004	2004	3	6-8 WEEKS	
118	115KV BUS - SOUTH BUS TRIPPING RELAY A94A (FOR B)	ALSTOM MVAJ	MVAJ13L1GB0771A	809015D	-	2004	3	6-8 WEEKS	
119	115KV BUS - SOUTH BUS TRIPPING RELAY A94B (FOR B)	ALSTOM MVAJ	MVAJ11D1GB0771A	552105L	-	2004	3	6-8 WEEKS	
120									
121									
122									
123									
124									
125									
126									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**WATSON T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
1	**115KV HIGH FALLS #1 & XFMR T1** BACK UP PROTECTION								**NOTE**: 115KV LINE HAS ONLY OVERCURRENT PROTECTION
2	115KV HIGH FALLS #1 & XFMR T1 BREAKER FAILURE 62BF-1302	ALSTOM KCEG140	KCEG14001F15MEE	073097J	1997	1998	4	**OBSOLETE**	
3	115KV HIGH FALLS #1 & XFMR T1 OVERLOAD PROTECTION	ALSTOM KCEG140	KCEG14001F15MEE	073100J	1997	1998	4	**OBSOLETE**	NON-DIRECTIONAL OVERCCURENT PROTECTION COMBINED WITH 115KV HIGH FALLS LINE NO. 1 AND TRANSFORMER T1
4	115KV HIGH FALLS #1 & XFMR T1 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	074454J	-	1998	3		
5	115KV HIGH FALLS #1 & XFMR T1 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771A	817040H	-	1998	3		
6									
7	**115KV HIGH FALLS #1 & XFMR T2** BACK UP PROTECTION								**NOTE**: 115KV LINE HAS ONLY OVERCURRENT PROTECTION
8	115KV HIGH FALLS #1 & XFMR T2 OVERLOAD PROTECTION 51B-T2	ALSTOM KCEG140	KCEG14001F15MEE	073099J	1997	1998	4	**OBSOLETE**	NON-DIRECTIONAL OVERCCURENT PROTECTION COMBINED WITH 115KV HIGH FALLS LINE NO. 2 AND TRANSFORMER T2
9	115KV HIGH FALLS #1 & XFMR T2 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	817045H	-	1998	3		
10									
11									
12									
13									
14									
15									
16									
17									
18									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**WATSON T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
19	**115KV/34.5KV TRANSFORMER T1** 43/60/75 MVA								
20	115KV/34.5KV TRANSFORMER T1 A' PROTECTION	ALSTOM KBCH120	KBCH12001P15MEI	217475N	2001	2001	3	1-2 BUSINESS DAYS	**REPLACED IN 2001**
21	115KV/34.5KV TRANSFORMER T1 B' PROTECTION	GEC ALSTOM KCEG140	KCEG14001F15MEE	201878J	1997	1998	4	**OBSOLETE**	
22	115KV/34.5KV TRANSFORMER T1 TRIPPING RELAY 94T1	ALSTOM MVAJ	MVAJ11D1GB0771A	073126J	-	1998	3	6-8 WEEKS	
23	115KV/34.5KV TRANSFORMER T1 TRIPPING RELAY 94BF1	ALSTOM MVAJ	MVAJ11D1GB0771A	073133J	-	1998	3	6-8 WEEKS	
24	115KV/34.5KV TRANSFORMER T1 TRIP CCT. SUPERVISION T74	ALSTOM MVAX	MVAX21C1DD0754	713994H	-	1998	3	6-8 WEEKS	
25									
26	**115KV/34.5KV TRANSFORMER T2** 43/60/75 MVA								
27	115KV/34.5KV TRANSFORMER T2 A' PROTECTION	ALSTOM KBCH120	KBCH12001P15MEI	217474N	2001	2001	3	1-2 BUSINESS DAYS	**REPLACED IN 2001**
28	115KV/34.5KV TRANSFORMER T2 B' PROTECTION	GEC ALSTOM KCEG140	KCEG14001F15MEE	003212J	1997	1998	4	**OBSOLETE**	
28	115KV/34.5KV TRANSFORMER T2 TRIPPING RELAY 94T2	ALSTOM MVAJ	MVAJ11D1GB0771A	073130J	-	1998	3	6-8 WEEKS	
30	115KV/34.5KV TRANSFORMER T2 TRIPPING RELAY 94BF2	ALSTOM MVAJ	MVAJ11D1GB0771A	817039H	-	1998	3	6-8 WEEKS	
31	115KV/34.5KV TRANSFORMER T2 TRIP CCT. SUPERVISION T74	ALSTOM MVAX	MVAX21C1DD0754	714000H	-	1998	3	6-8 WEEKS	
32									
33									
34									
35									
36									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**WATSON T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
37	**34.5KV WAWA NO. 1** A' PROTECTION	AREVA KCEG142	KCEG14201V51EEE	3284479	1999	2010	3	1-2 BUSINESS DAYS	DIRECTIONAL OVERCURRENT RELAY A67/67N/51/51N **REPLACED IN YEAR 2010**
38	34.5KV WAWA NO. 1 B' PROTECTION	GEC ALSTOM KCEG142	KCEG14201F51EEB	325031L	1999	1998	3	1-2 BUSINESS DAYS	DIRECTIONAL OVERCURRENT RELAY B67/67N/51/51N+62BF
39	34.5KV WAWA NO. 1 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771	073122J	-	1998	3	6-8 WEEKS	
40	34.5KV WAWA NO. 1 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771	073125J	-	1998	3	6-8 WEEKS	
41	34.5KV WAWA NO. 1 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771	073131J	-	1998	3	6-8 WEEKS	
42	34.5KV WAWA NO. 1 TRIP CCT. SUPERVISION 74T	ALSTOM MVAX	MVAX21C1DD0754	713992H	-	1998	3	6-8 WEEKS	
43									
44	**34.5KV WAWA NO. 2** A' PROTECTION	GEC ALSTOM KCEG140	KCEG14001F15MEC	676057F	1994	2010	4	**OBSOLETE**	DIRECTIONAL OVERCURRENT RELAY A67/67N/51/51N **REPLACED IN YEAR 2010**
45	34.5KV WAWA NO. 2 B' PROTECTION	GEC ALSTOM KCEG142	KCEG14201F51EEA	256656J	1997	1998	3	1-2 BUSINESS DAYS	DIRECTIONAL OVERCURRENT RELAY B67/67N/51/51N+62BF
46	34.5KV WAWA NO. 2 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771	817027H	-	1998	3	6-8 WEEKS	
47	34.5KV WAWA NO. 2 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771	817026H	-	1998	3	6-8 WEEKS	
48	34.5KV WAWA NO. 2 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771	073116J	-	1998	3	6-8 WEEKS	
49	34.5KV WAWA NO. 2 TRIP CCT. SUPERVISION 74T	ALSTOM MVAX	MVAX21C1DD0754	713997H	-	1998	3	6-8 WEEKS	
50									
51									
52									
53									
54									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:	**GREAT LAKES POWER TRANSMISSION (GLPT)**	**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:	**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**	**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
	GLPT ADDENDUM NO. 2010-015-A1004	**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:	**WATSON T. S.**	

ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY MODEL #	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	GLPT FAILURE REPORT/COMMENTS
55	**34.5KV SCOTT NO. 1** A' PROTECTION	ALSTOM KCEG142	KCEG14201F51EEE	334239L	1999	2010	3	1-2 BUSINESS DAYS	**REPLACED IN YEAR 2010**
56	34.5KV SCOTT NO. 1 B' PROTECTION	ALSTOM KCEG142	KCEG14201F51EEE	325032L	1999	2010	3	1-2 BUSINESS DAYS	**REPLACED IN YEAR 2010**
57	34.5KV SCOTT NO. 1 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	073210J	-	1998	3	6-8 WEEKS	
58	34.5KV SCOTT NO. 1 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	073132J	-	1998	3	6-8 WEEKS	
59	34.5KV SCOTT NO. 1 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771A	073134J	-	1998	3	6-8 WEEKS	
60	34.5KV SCOTT NO. 1 TRIP CCT. SUPERVISION 74T	ALSTOM MVAX	MVAX21C1DD0754	714002H	-	1998	3	6-8 WEEKS	
61									
62	**34.5KV SCOTT NO. 2** A' PROTECTION	ALSTOM KCEG142	KCEG14201F51EEA	256657J		1998	3	1-2 BUSINESS DAYS	
63	34.5KV SCOTT NO. 2 B' PROTECTION	ALSTOM KCEG140	KCEG14001F51MEC	373218G		1998	4	**OBSOLETE**	
64	34.5KV SCOTT NO. 2 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	377333G	-	1998	3	6-8 WEEKS	
65	34.5KV SCOTT NO. 2 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	817042H	-	1998	3	6-8 WEEKS	
66	34.5KV SCOTT NO. 2 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771A	073124J	-	1998	3	6-8 WEEKS	
67	34.5KV SCOTT NO. 2 TRIP CCT. SUPERVISION 74T	ALSTOM MVAX	MVAX21C1DD0754	713993H	-	1998	3	6-8 WEEKS	
68									
69									
70									
71									
72									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**WATSON T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
73	**34.5KV McPHAIL NO. 1** A' PROTECTION	ALSTOM KCEG140	KCEG14001F51MEE	074446J	1997	2010	4	**OBSOLETE**	DIRECTIONAL OVERCURRENT RELAY A67/67N/51/51N **REPLACED IN YEAR 2010**
74	34.5KV McPHAIL NO. 1 B' PROTECTION	ALSTOM KCEG142	KCEG14201F51EEE	354507L	1999		3	1-2 BUSINESS DAYS	**REPLACED IN YEAR 2010**
75	34.5KV McPHAIL NO. 1 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	073119J	-	1998	3	6-8 WEEKS	DIRECTIONAL OVERCURRENT RELAY A67/67N/51/51N+BF
76	34.5KV McPHAIL NO. 1 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	073123J	-	1998	3	6-8 WEEKS	
77	34.5KV McPHAIL NO. 1 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771A	073117J	-	1998	3	6-8 WEEKS	
78	34.5KV McPHAIL NO. 1 TRIP CCT. SUPERVISION 74T	ALSTOM MVAX	MVAX21C1DD0754	713996H	-	1998	3	6-8 WEEKS	
79									
80	**34.5KV McPHAIL NO. 2** A' PROTECTION	ALSTOM KCEG142	KCEG14201F51EEA	155839J	1997	1998	3	1-2 BUSINESS DAYS	DIRECTIONAL OVERCURRENT RELAY A67/67N/51/51N
81	34.5KV McPHAIL NO. 2 B' PROTECTION	ALSTOM KCEG142	KCEG14201F51EEA	157086J	1997	1998	3	1-2 BUSINESS DAYS	DIRECTIONAL OVERCURRENT RELAY A67/67N/51/51N+BF
82	34.5KV McPHAIL NO. 2 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	377338G	-	1998	3	6-8 WEEKS	
83	34.5KV McPHAIL NO. 2 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	073129J	-	1998	3	6-8 WEEKS	
84	34.5KV McPHAIL NO. 2 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771A	349051G	-	1998	3	6-8 WEEKS	
85	34.5KV McPHAIL NO. 2 TRIP CCT. SUPERVISION 74T	ALSTOM MVAX	MVAX21C1DD0754	723213H	-	1998	3	6-8 WEEKS	
86									
87									
88									
89									
90									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		GREAT LAKES POWER TRANSMISSION (GLPT)							GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS
PROJECT REFERENCE:		OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY							GLPT PROJECT MANAGERS: DAN S./JIM TAIT
		GLPT ADDENDUM NO. 2010-015-A1004							ACCOMPANIED BY: BOB H./DON DOWDING
TRANSMISSION STATION:		WATSON T. S.							GLPT FAILURE REPORT/COMMENTS
ITEM No.	FEEDER/TRANSFORMER	RELAY MAKE/TYPE	RELAY MODEL #	SERIAL NUMBER	YEAR OF MANUF.	YEAR OF INSTAL.	CONDITION (SEE THE KEY)	LEAD TIME FOR SPARES	
91	**34.5KV DUNFORD NO. 1** A' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	320377N	2002	2002	2	1-2 BUSINESS DAYS	**REPLACED IN YEAR 2002** DIRECTIONAL OVERCURRENT PROTECTION A67/67N/51/51N
92	34.5KV DUNFORD NO. 1 B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	320378N	2002	2002	2	1-2 BUSINESS DAYS	**REPLACED IN YEAR 2002** DIRECTIONAL OVERCURRENT PROTECTION B67/67N/51/51N
93	34.5KV DUNFORD NO. 1 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	817044H	-	1998	3	6-8 WEEKS	
94	34.5KV DUNFORD NO. 1 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	073118J	-	1998	3	6-8 WEEKS	
95	34.5KV DUNFORD NO. 1 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771A	073121J	-	1998	3	6-8 WEEKS	
96	34.5KV DUNFORD NO. 1 TRIP CCT. SUPERVISION T74	ALSTOM MVAX	MVAX21C1DD0754	714003H	-	1998	3	6-8 WEEKS	
97									
98	**34.5KV DUNFORD NO. 2** A' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	136926N	2002	2002	2	1-2 BUSINESS DAYS	**REPLACED IN YEAR 2002** DIRECTIONAL OVERCURRENT PROTECTION A67/67N/51/51N
99	34.5KV DUNFORD NO. 2 B' PROTECTION	ALSTOM MiCOM P141	P141311A1A0050A	136928N	2002	2002	2	1-2 BUSINESS DAYS	**REPLACED IN YEAR 2002** DIR. OVERCURRENT PROTECTION B67/67N/51/51N+62BF
100	34.5KV DUNFORD NO. 2 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	073128J	-	1998	3	6-8 WEEKS	
101	34.5KV DUNFORD NO. 2 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	817043H	-	1998	3	6-8 WEEKS	
102	34.5KV DUNFORD NO. 2 TRIPPING RELAY 94BF	ALSTOM MVAJ	MVAJ11D1GB0771A	349052G	-	1998	3	6-8 WEEKS	
103	34.5KV DUNFORD NO. 2 TRIP CCT. SUPERVISION T74	ALSTOM MVAX	MVAX21C1DD0754	723209H	-	1998	3	6-8 WEEKS	
104									
105									
106									
107									
108									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

GLPT EXISTING RELAYS DATA

OneLine Engineering Inc.
63 Church Street. Suite 301St. Catharines, ON L2R 3C4
Phone: 905-688-6857 Fax: 905-688-6926

CLIENT:		**GREAT LAKES POWER TRANSMISSION (GLPT)**							**GLPT MANAGER, S. P. & ENG.: GARY GAZANKAS**
PROJECT REFERENCE:		**OLE PROJECT NO. 10-003: REPLACEMENT OF PROTECTIVE RELAYS STUDY**							**GLPT PROJECT MANAGERS: DAN S./JIM TAIT**
		GLPT ADDENDUM NO. 2010-015-A1004							**ACCOMPANIED BY: BOB H./DON DOWDING**
TRANSMISSION STATION:		**WATSON T. S.**							**GLPT FAILURE REPORT/COMMENTS**
ITEM No.	**FEEDER/TRANSFORMER**	**RELAY MAKE/TYPE**	**RELAY MODEL #**	**SERIAL NUMBER**	**YEAR OF MANUF.**	**YEAR OF INSTAL.**	**CONDITION (SEE THE KEY)**	**LEAD TIME FOR SPARES**	
109	**34.5KV BUS 1** A' PROTECTION	ALSTOM MFAC	MFAC34F1BA0001A	650068H	1996	1998	3	SEE NOTE	**NOTE:** NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
110	34.5KV BUS 1 B' PROTECTION	GEC ALSTOM KCEG140	KCEG14001F15MEE	073109J	1997	1998	4	**OBSOLETE**	
111	34.5KV BUS 1 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	377335G	-	1998	3	6-8 WEEKS	
112	34.5KV BUS 1 TRIPPING RELAY 94A21	ALSTOM MVAJ	MVAJ11D1GB0771A	377337G	-	1998	3	6-8 WEEKS	
113	34.5KV BUS 1 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	377334G	-	1998	3	6-8 WEEKS	
114									
115	**34.5KV BUS 2** A' PROTECTION	ALSTOM MFAC	MFAC34F1BA0001A	632406H	1996	1998	3	SEE NOTE	**NOTE**: NOT IN STOCK. DEFECTIVE RELAY WILL BE SENT TO UK FOR REPAIR. IT WILL TAKE TWO WEEKS.
116	34.5KV BUS 2 B' PROTECTION	GEC ALSTOM KCEG140	KCEG14001F15MEE	073103J	1997	1998	4	**OBSOLETE**	
117	34.5KV BUS 2 TRIPPING RELAY 94A	ALSTOM MVAJ	MVAJ11D1GB0771A	349053G	-	1998	3	6-8 WEEKS	
118	34.5KV BUS 2 TRIPPING RELAY 94A21	ALSTOM MVAJ	MVAJ11D1GB0771A	377331G	-	1998	3	6-8 WEEKS	
119	34.5KV BUS 2 TRIPPING RELAY 94B	ALSTOM MVAJ	MVAJ11D1GB0771A	377336G	-	1998	3	6-8 WEEKS	
120									
121	**34.5KV BUS TIE BUS 1/BUS 2** TRIP CCT. SUPERVISION 74T	ALSTOM MVAX	MVAX21C1DD0754	713999H	-	1998	3	6-8 WEEKS	
122									
123									
124									
125									
126									

CONDITION KEY:
1. GOOD 2. ACCEPTABLE 3. OLD
4. OBSOLETE 5. UNRELIABLE 6. FAULTY

APPENDIX G

Correspondence with Manufacturers

CO-11

jean-pierre.r.vien to: nmohiuddin 01/11/2010 10:23 PM

History: This message has been replied to.

These CO-11 are still available. Delivery 6-8 weeks. Estimated service life more than 20 years.

Dear Naseer ,

Deliver for the spare MiCOM relays if we have it in stock is one or two days .Same thing for K series we have plenty of K-series here in our stock and can be delivered in one or two days . For MFAC/MCAG Since these are old relays we don't have it in stock and if you have a failure we have to send them to UK for repair and it will take normally two weeks for repair .

But as per my experience it is very rare to have a failure for MFAC or MCAG .

Time for repair is two weeks .

Let me know if you have any more question .

Best regards,
Amirreza

Amirreza Mohtadi | Schneider Electric | Energy Business | Canada | Automation Support Specialist
Phone: +1 450 659 8921 ext 697 | Fax: +1 450 659 8900 | Mobile: +1 514 513 4698
Email: amirreza.mohtadi@areva-td.com | Site: www.areva-td.com | Address: 1400 rue Industrielle La Prairie,QC J5R2E5 Canada

Naseer Mohiuddin <NMohiuddin@glp.ca>

24/11/2010 08:37 AM

To Amirreza MOHTADI/CACAL01/TDE/AREVA-TD@ATD
cc
Subject Re: Fw: RE RE GLP relay information

Hi Amirreza,

Thank you for sending the CD. Further to our previous discussion, we need the following information:

1 Delivery period of spare P series, KCEG 142, KBCH 120 and MFAC/MCAG relays.

2. Time to repair the relays.

Your earliest reply would be highly appreciated.

Regards,

Naseer Mohiuddin, B. Sc. Eng.
Senior Technical Advisor
Great Lakes Power Transmission
2 Sackville Road, Suite B
Sault Ste. Marie ON P6B 6J6
Tel: 705 254 7444 Ext. 799

Fax 705 759 2218
Email: nmohiuddin@glp.ca

From:	amirreza.mohtadi@areva-td.com
To:	Naseer Mohiuddin <NMohiuddin@glp.ca>
Date:	29/10/2010 12:29 PM
Subject:	Re: Fw: RE RE GLP relay information

Note: Discussed with Mr. Amirreza Mohtadi about Delivery Period of MIDOS Series relays (MVAJ and MVAX). The Delivery Period is 6-8 weeks.

Dear Mr. Mohiuddin,

As discussed over the phone with Mr. Amirreza Mohtadi. Please find attached below the informations that you asked for.

Please be informed that the following relays are still active and available: all P series, KCEG112, KCEG142, KBCH120 and MFAC34.

The LFZP131 and KCEG140 are obsolete relays. We can offer a MICOMFIT solution as replacement.

If you are interested we can send you a quote.

Thank you and Best Regards

Samer Abou Daher
Automation Service Support (Trainee)
Spécialiste support technique (Stagiaire)
AREVA T&D Automation
(Becoming ALSTOM Grid for Transmission products
and Schneider Electric for Distribution products)
Tel: 450-659-1399 ext. 644
Mail: Samer.Abou-Daher@areva-td.com

Richard BERNARD/CABRO01/TDE/AREVA-TD

2010-10-26 10:41

A Farhad MOSLEMI/CABRL01/TDE/AREVA-TD@ATD, Samer ABOU-DAHER/CABRO01/TDE/AREVA-TD@ATD
cc Dalil PARAISO/CABRO01/TDE/AREVA-TD@ATD, Liga ELE/CABRO01/TDE/AREVA-TD@ATD
Objet RE GLP relay informationLink

Thank you Farhad

I'm forwarding this to the support team, they should be able to handle this request

Samer

Please take a look at this request

Thank you in advance

Regards

Richard J Bernard
Inside sales Representative
Areva T&D Canada Inc
1400 Rue Industrielle
La Prairie,QC J5R 2E5
Canada
Tel:450-659-8921 Ext 659
Cell:514-463-3000
Fax:450-659-8900
E-Mail:Richard.Bernard@areva-td.com

Farhad MOSLEMI/CABRL01/TDE/AREVA-TD

26/10/2010 10:35 AM

A Richard BERNARD/CABRO01/TDE/AREVA-TD@ATD
cc Dalil PARAISO/CABRO01/TDE/AREVA-TD@ATD
Objet GLP relay information

Hi Richard

Attached please find the list of relays at Great Lake Power,
they are looking for some information regarding to life expectation and spare part existence.
I will appreciate if you could provide them this information, let me know if you want me to do anything with that.

Regards
Farhad
----- Forwarded by Farhad MOSLEMI/CABRL01/TDE/AREVA-TD on 26/10/2010 10:31 AM -----
Naseer Mohiuddin <NMohiuddin@glp.ca>

26/10/2010 10:26 AM

To Farhad MOSLEMI/CABRL01/TDE/AREVA-TD@ATD
cc
Subject Re: Contact information

Hi Farhad,

Thank you very much for your kind reply. Attached is the list of protective relays (ALSTOM) for which we need their year of manufacture, life expectancy and availability of spare relays.

Thanking you again.

Regards,

Naseer Mohiuddin
Great Lakes Power Transmission

2-Sackville Road, Suite B
Sault Ste. Marie, ON P6B 6J6
Tel: 1-705-254-744 Ext. 799
Fax: 1-705-759-2218
Email: nmohiuddin@glp.ca

From:	farhad.moslemi@areva-td.com
To:	nmoHiuddin@glp.ca
Date:	26/10/2010 10:03 AM
Subject:	Contact information

Hi Naseer

It was nice talking to you,
Following please find my contact information,

Regards
Farhad Moslemi
Senior Application engineer
Areva T&D Canada Inc.
3410 Burlington ON, L7N3T2
Canada
Tel: +1 (905) 333-2030
Cel: +1 (905) 691-7405
E-mail: farhad.moslemi@areva-td.com
Website: http://WWW.areva-td.com

[attachment "Relays Information.doc" deleted by Samer ABOU-DAHER/CABRO01/TDE/AREVA-TD]

Naseer,

Good to hear from you. I have responded below.
I trust this is what you require.

Regards,
Eric Langford
(416) 490-6546
eric@langford-assoc.com

From: Naseer Mohiuddin [mailto:NMohiuddin@onelineeng.com]
Sent: November 26, 2010 9:46 AM
To: sales@langford-assoc.com
Subject: Availbility of Spare Relays

Hi there,

I am pleased to inform you that we are working on Study of Protective Relays of Great Lakes Power Transmission (GLPT), Sault St. Marie. The GLPT system has a Basler relay type BEI-25A in service. For our study, we need the following information about the relay:

1. Avaibility of spare relay and the delivery period.

<EL> 2 weeks.

2. Life expectancy of the relay type: BEI-25A.

<EL> 20+ years (??) It is solid state and the field MTBF is very, very long. (we'll both be long gone!!)

3. Time to repair defective relay.

<EL> 2 weeks.

Kindly provide the above information at your econvenience.

Thanking you.

Regards,

Naseer Mohiuddin,
Senior Technical Advisor
OneLine Engineering Inc.,
63 Church Street, Suite 301,
St. Catharines, Ontario. L2R 3C4
Phone: 905-688-6857
Cell: 289-213-4560
Fax: 905-688-6926
E-mail: nmohiuddin@onelineeng.com
Web: www.onelineeng.com

Thanks Naseer : my next trip to S.S.Marie is Dec 8 + Dec 9 / 2010

- will check with you that week to determine when you may be available

Regards, Dennis

From: Naseer Mohiuddin [mailto:NMohiuddin@glp.ca]
Sent: Tuesday, November 23, 2010 8:35 AM
To: Dennis Dixon
Subject: Re: GE Multltin information

Thank you, Dennis, for your kind reply. It is quite clear and satisfactory. I will be in Sault Ste. Marie till Christmas holidays. Please let us know when you will be here.

Looking forward to meet with you.

Regards,

Naseer Mohiuddin, B. Sc. Eng.
Senior Technical Advisor
Great Lakes Power Transmission
2 Sackville Road, Suite B
Sault Ste. Marie ON P6B 6J6
Tel: 705 254 7444 Ext. 799
Fax 705 759 2218
Email: nmohiuddin@glp.ca

From:	"Dennis Dixon" <dennis@chesscontrols.com>
To:	<nmohiuddin@glp.ca>
Date:	19/11/2010 09:32 AM
Subject:	GE Multltin information

Good Morning Naseer :

Please see GE Multilin reply below on questions on UR relays & D90 Plus

- Multilin product guide was delivered to your office yesterday

- back in S.S.Marie in approx 2 -3 weeks , will make an appointment to introduce myself

Regards, Dennis
Chess Controls Inc
705-682-2828

To: Dennis Dixon
Subject: RE: G.L.Power

Dennis

1) MTBF document is attached
Life Span of UR relay from field experience: The first relay was installed in 1998 and still very healthy operating. We estimate the life span of the UR in 25 years.

2) Availability of Spare Parts: We still support spare parts for the first UR relay delivered in 1998. The modular mechanical design of the UR relay allows us to upgrade electronic components very easily; for example if component is not longer available we can change it for an other one and customer will only has to change a specific module, not the whole relay.

3) Price for basic D90Plus model D90P-AE-ES01LSS-XHXXAAXX01X Cnd $14,800

4) IJS and IAC relays will be available for the foreseeable future. We have being manufacturing them for the last 30/50 years and will continue to do so. When we tried to stop manufacturing customer outcry forced us to put them back in production. Delivery varies according to product from 15 business days to 50 business days

5) Digital and numerical relays are different names for relay having the same technology, this is, use of microprocessor to perform protection relaying and control. Digital is because the relay digitize current and voltage waveforms and then manipulates their samples using numerical algorithms.

Dennis, pls ask Naseer to call me directly at 416 399 3379. Also ask if he has got the GE Catalogue

Hope this helps
Gustavo

From: Naseer Mohiuddin [mailto:NMohiuddin@glp.ca]
Sent: Monday, November 01, 2010 9:14 AM
To: multilin.online (GE Energy Services)
Cc: Brunello, Gustavo (GE Energy Services); ~Cons/Ind Literature.Multilin
Subject: Re: [CASE:700030956] GE Multilin Product Catalog
Hello May,

Thank you for your kind consideration for sending the requested GE catalogues. I have received the catalogues. I would like to inform you that I am near completion of the Study for Replacement of Protective Relays in the Great Lakes Power Transmission system. At this stage, I need the following information:

1. Life Span of the GE Multilin digital relays, based on the GE field experience. Also what is MTBF of the relays.

2. Availability of the spare relays.

3. Price and delivery period of distance relay D90Plus.

4. Availability and delivery period of electro-mechanical relays: IJS and IAC. How long these will be kept active?

5. The GE UR relays are stated as Digital Relays. Is there any difference between Numerical and Digital Relays?

Looking forward from hearing from you soon.

Best regards,

Naseer Mohiuddin, B. Sc. Eng.
Senior Technical Avisor
Great Lakes Power Transmission
2 Sackville Road, Suite B
Sault Ste. Marie ON P6B 6J6
Tel: 705 254 7444 Ext. 799
Fax 705 759 2218
Email: nmohiuddin@glp.ca

[attachment "GE MTBF UR May 30, 2008.pdf" deleted by Naseer Mohiuddin/GLP]

Date: November 1, 2010

Hi Naseer,
With respect to your questions below...

1. Do all the SEL relays have Numerical aspect? Is there any difference between Numerical or Digital relays?
SEL refers to their relays as IEDs (Intelligent Electronic Devices) or Digital relays; for all intents and purposes the terms numerical and digital are interchangeable.

2. What is Life Expectancy or Lifespan of SEL relays keeping in view of the natural aging.
I will obtain an official statement from SEL for this question.

Also, the typical delivery time for SEL 3351 computing platforms is 13 business days for manufacture, plus shipment into Canada(this can be from 1-5 days depending on shipping method). Most other SEL products are 10-14 business days for manufacture, plus shipping time. This usually translates to a total time of 3 to 4 weeks on the calendar from the time you place an order to the time you receive the product.

I can visit the St. Catharine's office Wednesday November 10th at 10:30AM. Let me know if this time works well for you.

Thanks
Joe

From: Naseer Mohiuddin [mailto:NMohiuddin@onelineeng.com]
Sent: Friday, October 29, 2010 11:29 AM
To: jgalliera@pro-techpower.com
Subject: RE: SEL Product Information

Hi Joe,

It was nice talking to you today on phone.

The following information is requested for SEL relays:

1. Do all the SEL relays have Numerical aspect? Is there any difference between Numerical or Digital relays?

2. What is Life Expectancy or Lifespan of SEL relays keeping in view of the natural aging.

Have a good wekend!

Thanks and Best Regards,

Naseer Mohiuddin,
OneLine Engineering Inc.,
63 Church Street, Suite 301,
St. Catharines, Ontario, L2R 3C4
Phone: 905-688-6857
Cell: 289-213-4560
Fax: 905-688-6926
E-mail: nmohiuddin@onelineeng.com
Web: www.onelineeng.com

From: Joe Galliera [mailto:jgalliera@pro-techpower.com]
Sent: Thu 9/2/2010 11:07 AM
To: Naseer Mohiuddin
Subject: SEL Product Information

Hello Naseer,
Good to meet with you on Tuesday at GLPT; let me know when you are back in St. Catharines. I spoke with Amy Sinclair and she tells me that she will contact you to discuss some of the technical questions you had during our meeting.

Below is a statement that SEL has given to other customers regarding reliability of some of the products you mentioned, let me know if you would like a formal statement from them on company letterhead.

The SEL-3354 Embedded Automation Computing Platform was released in September 2009. We do not yet have statistically significant observed field reliability data for the SEL-3354; therefore the Mean Time Between Failures (MTBF) data for the SEL-3354 is estimated from the SEL-3351 due to product similarity.

The SEL-3530 Real-Time Automation Controller (RTAC) was released in October of 2009. We do not yet have statistically significant observed field reliability data for the SEL-3530; therefore the MTBF for the SEL-3530 is estimated from the SEL-2032 due to product similarity.

The table below includes Mean Time Between Failures (MTBF) data for the last 12 months through July 2010. Observed reliability is based on units returned by customers to SEL for repair service and reflects typical configuration on those products. Because of our 10-year warranty, we are able to maintain accurate measurements of removal experience. We investigate each unit returned for repair and we review all service activity for trends that may indicate a design, material, or process problem. If there is a trend, we implement corrective actions to prevent recurrence.

Product	**SEL MTBF**
SEL-451	**490 years**
SEL-3351	**250 years**
SEL-3354	**250 years**
SEL-3530	**850 years**

Joe Galliera
Pro-Tech Power Sales Inc.
6-295 Queen Street East
Suite #387
Brampton, Ontario L6W 4S6
Office: 905-866-6060
Cell: 905-933-3060
Fax: 1-866-821-3102 (toll free)
jgalliera@pro-techpower.com
www.pro-techpower.com

Date: November 1, 2010

Hello Naseer,
The following is a statement from SEL regarding the expected service life of their products...

"The expected service life performance of SEL products is a minimum of 25 years, when operated within specified conditions. SEL product service life is limited by long-term degradation of electrolytic capacitors in the unit power supply module. To date, SEL products have been in continuous service reliably for over 25 years. Because of our design methodology, product service can be extended beyond 25 years with power supply replacement."

I trust this statement is sufficient for your report.

See you next week.

Joe

From: Naseer Mohiuddin [mailto:NMohiuddin@onelineeng.com]
Sent: Friday, October 29, 2010 11:29 AM
To: jgalliera@pro-techpower.com
Subject: RE: SEL Product Information

Hi Joe,

It was nice talking to you today on phone.

The following information is requested for SEL relays:

1. Do all the SEL relays have Numerical aspect? Is there any difference between Numerical or Digital relays?

2. What is Life Expectancy or Lifespan of SEL relays keeping in view of the natural aging.

Have a good wekend!

Thanks and Best Regards,
Naseer Mohiuddin,
OneLine Engineering Inc.,
63 Church Street, Suite 301,
St. Catharines, Ontario, L2R 3C4
Phone: 905-688-6857
Cell: 289-213-4560
Fax: 905-688-6926
E-mail: nmohiuddin@onelineeng.com
Web: www.onelineeng.com

From: Joe Galliera [mailto:jgalliera@pro-techpower.com]
Sent: Thu 9/2/2010 11:07 AM

To: Naseer Mohiuddin
Subject: SEL Product Information

Hello Naseer,
Good to meet with you on Tuesday at GLPT; let me know when you are back in St. Catharines. I spoke with Amy Sinclair and she tells me that she will contact you to discuss some of the technical questions you had during our meeting.

Below is a statement that SEL has given to other customers regarding reliability of some of the products you mentioned, let me know if you would like a formal statement from them on company letterhead.

The SEL-3354 Embedded Automation Computing Platform was released in September 2009. We do not yet have statistically significant observed field reliability data for the SEL-3354; therefore the Mean Time Between Failures (MTBF) data for the SEL-3354 is estimated from the SEL-3351 due to product similarity.

The SEL-3530 Real-Time Automation Controller (RTAC) was released in October of 2009. We do not yet have statistically significant observed field reliability data for the SEL-3530; therefore the MTBF for the SEL-3530 is estimated from the SEL-2032 due to product similarity.

The table below includes Mean Time Between Failures (MTBF) data for the last 12 months through July 2010. Observed reliability is based on units returned by customers to SEL for repair service and reflects typical configuration on those products. Because of our 10-year warranty, we are able to maintain accurate measurements of removal experience. We investigate each unit returned for repair and we review all service activity for trends that may indicate a design, material, or process problem. If there is a trend, we implement corrective actions to prevent recurrence.

Product	**SEL MTBF**
SEL-451	**490 years**
SEL-3351	**250 years**
SEL-3354	**250 years**
SEL-3530	**850 years**

Joe Galliera
Pro-Tech Power Sales Inc.
6-295 Queen Street East
Suite #387
Brampton, Ontario L6W 4S6
Office: 905-866-6060
Cell: 905-933-3060

Fax: **1-866-821-3102 (toll free)**
jgalliera@pro-techpower.com
www.pro-techpower.com

July 20, 2018

Mr. Jeffery Smith,
Director, Regulatory Affairs
Hydro One Networks Inc.

Re: Support in Development of the Hydro One Sault Ste. Marie LP ("HOSSM") Transmission System Plan.

Dear Mr. Smith,

This letter is to confirm that METSCO Energy Solutions Inc. ("METSCO") has assisted HOSSM with the development of a consolidated 2018-2026 Transmission System Plan ("TSP"). The TSP has been prepared in accordance with Chapters 2, 3 and 5 of the Ontario Energy Board's (OEB) *Filing Requirements for Electricity Transmission Applications* published on February 11, 2016.

The TSP supports the OEB's Renewed Regulatory Framework objectives of Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance, and lays out a comprehensive planning framework that underpins the investments forecasted over the Plan period and the process features of the ongoing integration of HOSSM's system with that of Hydro One Networks.

Sincerely,

Dmitry Balashov

Director, Utility Strategy and Economic Regulation

METSCO Energy Solutions Inc.

CAPITAL PROJECTS AND EXPENDITURES

1. INTRODUCTION

Found in Exhibit B2, Tab 1, Schedule 1, Attachments 1 and 2, are the OEB Chapter 2 Appendices 2-AA Capital Projects and 2-AB Capital Expenditures respectively.

Variances found in Appendix 2-AA are due to the following:

1. The expenditures in 2013 and 2014 were lower than in subsequent years due to a strategic decision made by the parent company at that time. It was a planned cut-back of capital spending, and not based on issues with operations

2. For 2015 and 2016, the increase in Capital Expenditures was largely to support maintenance of the rate base. New Capital Expenditures would offset depreciation and rate base would largely stay the same.

3. There was an assumed similar level of capital spend in the plan for 2017 as in 2016. The reason for the increase in capital for 2017 compared to 2016 was due to $3.3M in spend related to Batchewana First Nation land rights acquisition/negotiation that was not in Hydro One Sault Ste. Marie’s budget as well as some capital project carryover from 2015 and 2016 that was ultimately deferred into 2017 (and was therefore not in the 2017 budget). Had things gone exactly to plan in 2017, the in-service capital projects would have totalled $10.3M.

Variances found in Appendix 2-AB are due to the following:

1. As mentioned above, 2015 and 2016 total expenditure is lower than plan due to some capital projects not being able to be completed on schedule and completion was deferred into 2017.

2. As mentioned above, 2017 is 41% higher than plan due to unplanned Batchewana First Nation land rights acquisition costs ($3.3M) combined with 2015/2016 work that was completed in 2017 but also not included in the 2017 budget (would have been included in 2015 and 2016 plan and budget amounts).

Appendix 2-AA
Capital Projects Table

Projects	2013	2014	2015	2016	2017	2018
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
SYSTEM RENEWAL						
Pole Replacements:						
Algoma #3 and Northern Avenue	1,757,057					
Algoma #1,#2, #3		3,143,875				
Gartshore/Hogg			5,866,895			
Hollingsworth				2,729,280		
Andrews				145,379		
P21G					4,514,227	4,800,000
Magpie					183,812	
Anjigami				23,733		
Other	81,282		86,936	132,560	17,555	
Sub-Total	1,838,339	3,143,875	5,953,831	3,030,952	4,715,594	4,800,000
Transformer Replacements:						
Echo River	162,047					
MacKay	105,094					
Northern Avenue	242,560					
Magpie & Steelton				712,494		
MacKay T1					1,233,577	
Other		13,630				
Sub-Total	509,701	13,630	0	712,494	1,233,577	0
Battery Replacements:						
Watson TS		117,175				
Goulais Bay TS			127,529			
Sub-Total	0	117,175	127,529	0	0	0
Other:						
Hollingsworth conductor replacement				400,000		
Steephill conductor	30,213					
Other				173,038		
Sub-Total	30,213	0	0	573,038	0	0
SYSTEM RENEWAL SUBTOTAL	2,378,253	3,274,680	6,081,360	4,316,484	5,949,171	4,800,000
SYSTEM SERVICE						
Oil Containment Modifications:						
Watson TS	248,992					
Third Line TS		249,776				
Hollingsworth TS				164,707		
Sub-Total	248,992	249,776	0	164,707	0	0
Protection Upgrades:						
Watson TS					1,432,285	1,100,000
Anjigami TS					2,530,547	
Hollingsworth TS					238,735	
Sub-Total	0	0	0	0	4,201,567	1,100,000
Other:						
Reverification of relays at Third Line TS	154,358					
Highway 101 TS improvements			1,149,674			
Watson TS breaker installation				1,389,595		
MacKay TS Ground-grid				110,901		
Anjigami TS refurbishment				957,320	441,941	
SCADA dispatch training simulator	863,598					
Sub-Total	1,017,956	0	1,149,674	2,457,816	441,941	0
SYSTEM SERVICE SUBTOTAL	1,266,948	249,776	1,149,674	2,622,523	4,643,508	1,100,000
GENERAL PLANT						
Northland radio building replacement				225,322	2,746	
Gartshore radio building replacement					171,402	
Storage network update	132,596					
Land right acquisitions				970,250	3,339,235	
Telecommunications				216,912		
Computer software		40,709	442,322	371,519	25,906	30,000
Leasehold improvements	36,097			335,325	22,517	
Building upgrades	15,542	226,377	455,291		147,884	250,000
Fleet	179,287	151,910	251,595	127,028	27,035	
Minor Equipment	448,348	368,217	363,336	372,574	158,773	220,000
Other						100,000
Sub-Total	811,870	787,213	1,512,544	2,618,930	3,895,498	600,000
GENERAL PLANT SUBTOTAL	811,870	787,213	1,512,544	2,618,930	3,895,498	600,000
Miscellaneous	0	0	0	0	0	0
Total	**4,457,071**	**4,311,669**	**8,743,578**	**9,557,937**	**14,488,177**	**6,500,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***						
Total	**4,457,071**	**4,311,669**	**8,743,578**	**9,557,937**	**14,488,177**	**6,500,000**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated

First year of Forecast Period: *2018*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2013			2014			2015			2016			2017			2018	2019	2020	2021	2022
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--	-	-	-	-	-
System Renewal	1,860,387	2,378,253	27.8%	3,183,457	3,274,680	2.9%	5,780,000	6,081,360	5.2%	4,486,188	4,316,484	-3.8%	5,613,700	5,949,171	6.0%	5,100,000	3,000,000	8,000,000	7,900,000	5,900,000
System Service	1,284,996	1,266,948	-1.4%	249,000	249,776	0.3%	1,152,800	1,149,674	-0.3%	3,298,913	2,622,523	-20.5%	3,702,000	4,643,508	25.4%	1,300,000	1,300,000	2,600,000	2,800,000	5,500,000
General Plant	1,341,275	811,870	-39.5%	912,317	787,213	-13.7%	2,527,197	1,512,544	-40.1%	1,983,583	2,618,930	32.0%	975,402	3,895,498	299.4%	100,000	2,900,000	100,000	1,000,000	1,000,000
TOTAL EXPENDITURE	4,486,658	4,457,071	-0.7%	4,344,774	4,311,669	-0.8%	9,459,997	8,743,578	-7.6%	9,768,684	9,557,937	-2.2%	10,291,102	14,488,177	40.8%	6,500,000	7,200,000	10,700,000	11,700,000	12,400,000
System O&M	$ 10,100,000	$ 10,210,900	1.1%	$ 10,305,535	$ 10,304,457	0.0%	$ 10,821,095	$ 10,424,380	-3.7%	$ 11,121,876	$ 10,941,448	-1.6%	$ 11,121,876	$ 9,492,621	-14.6%	$ 9,449,000	$ 10,700,000	$ 11,000,000	$ 11,200,000	$ 11,400,000

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 12

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Notes on year over year Plan vs. Actual variances for Total Expenditures

2017 is 40.8% higher than plan due to unplanned Batchawana First Nation land rights acquisition costs ($3.3M) combined with 2015/2016 work that was completed in 2017.

Notes on Plan vs. Actual variance trends for individual expenditure categories

2017 General Plant Actual is 299.4% higher than plan due to the Batchawana First Nation land rights acquisition costs ($3.3M).

CAPITAL PLAN EVOLUTION

1. INTRODUCTION

Throughout the integration process, Hydro One and Hydro One Sault Ste. Marie ("HOSSM") have committed to investigating areas of opportunity to realize savings through productivity, efficiency and synergies. HOSSM will operationally integrate on October 1, 2018 and will financially integrate at a later time. One of the areas targeted for full review was the Capital Investment Plan.

Table 1[1] shows the investment levels that were submitted in the pre-filed evidence in the Hydro One Inc.'s S86 (2)(b) Leave to Purchase Voting Securities of Great Lakes Power Transmission Inc. ("GLPT") (proceeding EB-2016-0050). This table provided information pertaining to GLPT's assumed future cost structures using "without transaction" forecast of capital expenditures. The amounts shown were based on Hydro One Inc.'s review of GLPT's draft capital expenditure plan at that time.

Table 1 - GLPT's "Without Transaction" Forecast of Capital Expenditures

$Million	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	19.4	16.2	17.6	18.6	17.5	20.6	19.9	18.3	17.4	17.8

Table 2 shows the detailed Capital Plan that underpinned the "without transaction" forecast levels

[1] EB-2016-0050, Exhibit A, Tab 2, Schedule 1, Table 2, page 4

Table 2 - Detailed Capital Investment Plan (in C$ in thousands)

Capital Expenditures - Detailed	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Transmission Line Upgrades											
Wood Structure Replacements	2,738.5	6,002.2	6,390.1	1,929.6	1,607.4	1,766.5	6,992.2	6,929.8	7,032.8	7,025.3	**45,676.0**
Sault #3 115kV Line Upgrade	-	-	1,022.7	6,162.9	5,238.4	8,549.1	-	-	-	-	**20,973.1**
Engineering - Transmission Lines	300.0	430.8	498.1	756.5	634.3	572.6	440.8	542.7	468.3	554.9	**4,898.9**
Total Transmission Line Upgrades	**3,038.5**	**6,433.0**	**7,910.9**	**8,849.0**	**7,480.1**	**10,888.2**	**7,433.0**	**7,472.6**	**7,501.1**	**7,580.2**	**71,548.1**
Station Upgrades											
Watson Transmission Station Upgrade	1,350.0	-	-	-	-	-	-	-	-	-	**-**
Magpie Transmission Station CT Replacements	621.0	-	-	-	-	-	-	-	-	-	**-**
Northern Ave Supply Reinforcement	132.0	-	-	-	-	-	-	-	-	-	**-**
Anjigami Transmission Station Upgrade	1,013.4	1,832.9	-	-	-	-	-	-	-	-	**1,832.9**
Mackay Transmission Station - T1 Transformer Replacement	-	1,377.0	-	-	-	-	-	-	-	-	**1,377.0**
Watson Transmission Station Protection Upgrades	-	1,382.1		-	-	-	-	-	-	-	**1,382.1**
New Generation Network	-	510.0	520.2	-	-	-	-	-	-	-	**1,030.2**

Capital Expenditures - Detailed	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Echo River Transmission Station Upgrade	-	-	-	-	-	-	-	-	-	378.6	**378.6**
Third Line Transmission Station - T2 Transformer Replacement	-	3,372.2	2,630.3		-	-	-	1,053.3	-	-	**7,055.8**
Critical Spare Parts	-	-	520.2	530.6	541.2	-	-	-	-	-	**1,592.0**
Transformer Contingency Plan - Replacements & Spares	-	-	-	-	1,226.8	588.8	2,294.3	1,928.4	2,245.0	428.2	**8,711.6**
Hollingsworth Transmission Station Protection Upgrades	-	-	-	248.7	-	-	-	-	-	-	**248.7**
Mackay Transmission Station Relay Replacements	-	-	-	193.9	298.8	-	-	-	-	-	**492.7**
Steelton Transmission Station Upgrade	-	-	-	2,220.6	2,265.0	-	-	-	-	-	**4,485.6**
New Transmission Station - Replace Goulais & Batchawana	-	-	485.9	1,068.1	2,178.9	3,333.8	-	-	-	-	**7,066.7**
Security Camera Upgrades at Transmission Stations	-	-	-	-	541.2	-	-	-	-	-	**541.2**
Watson Transmission Station Upgrade (Switch Gear & Ring Bus)	-	-	-	-	-	-	-	831.6	1,507.6	1,170.5	**3,509.7**
Clergue Transmission Station Upgrade	-	-	-	-	-	-	3,770.6	1,752.0	3,638.4	3,846.9	**13,007.9**
Engineering - Transmission Stations	687.5	698.8	641.2	423.2	569.0	351.2	433.3	344.3	431.9	358.7	**4,251.6**

Capital Expenditures - Detailed	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Transmission Line/Station Emergency Work	370.4	168.3	171.7	175.1	178.6	182.2	180.3	182.9	185.7	188.4	**1,613.2**
Total Station Upgrades	**4,174.3**	**9,341.3**	**4,969.5**	**4,860.2**	**7,799.5**	**4,456.0**	**6,678.5**	**6,092.6**	**8,008.6**	**6,371.3**	**58,577.4**
System Equipment											
Fibre Optic Network Upgrades	-	726.8	299.1	-	-	-	1,638.8	1,663.2	1,687.9	2,329.5	**8,345.2**
SCADA Hardware Refresh	-	-	-	-	-	1,104.1	-	-	-	-	**1,104.1**
SCADA Asset Management	-	-	-	596.9	1,826.6	-	-	-	-	-	**2,423.5**
Relocation of Backup Control Centre	-	-	-	-	-	-	2,686.6	2,526.5	-	-	**5,213.0**
Radio System Upgrade	-	765.0	780.3	-	-	-	-	-	-	-	**1,545.3**
General SCADA, Telecom, Communications Upgrades	155.0	153.0	156.1	159.2	162.4	165.6	163.9	166.3	168.8	171.3	**1,466.6**
Information Technology Refresh - Hardware & Software	400.9	255.0	260.1	265.3	270.6	276.0	273.1	277.2	281.3	285.5	**2,444.1**
Transportation and Work Equipment	250.0	204.0	208.1	1,485.7	649.5	220.8	218.5	221.8	225.1	228.4	**3,661.8**
Total System Equipment	**805.9**	**2,103.8**	**1,703.7**	**2,507.1**	**2,909.1**	**1,766.5**	**4,980.9**	**4,854.9**	**2,363.0**	**3,014.6**	**26,203.6**
Land and Property Rights											
Third Line Transmission Station Storage Facility Building	-	714.0	-	-	-	-	-	-	-	-	**714.0**
W23K Line ROW Expansion	-	153.0	156.1	-	-	-	-	-	-	-	**309.1**
Land Acquisitions	892.0	-	1,040.4	1,061.2	-	-	1,092.5	1,058.8	-	-	**4,252.9**

Capital Expenditures - Detailed	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Minor Fixed Assets	324.8	234.6	129.0	130.2	194.8	198.7	196.7	199.6	202.5	205.6	**1,691.6**
General Building Upgrades	500.0	385.1	330.3	212.2	216.5	220.8	218.5	221.8	225.1	228.4	**2,258.6**
Total Land and Property Rights	**1,716.8**	**1,486.7**	**1,655.8**	**1,403.6**	**411.3**	**419.5**	**1,507.7**	**1,480.1**	**427.6**	**433.9**	**9,226.3**
Total Spend	**9,735.5**	**19,364.8**	**16,239.9**	**17,619.9**	**18,600.0**	**17,530.2**	**20,600.1**	**19,900.1**	**18,300.3**	**17,400.1**	**165,555.4**

In the process of integration after an acquisition, Capital expenditure reductions are expected to result from asset redundancy, the economic scale of operations and adopting new asset management and investment planning processes. The level of reductions realized can be hard to forecast without a firm understanding of the health indices of the assets and system operational constraints and issues. Reductions can also be affected by circumstances prevailing when operational integration plans are implemented, as well as external factors affecting operations such storms and extreme temperatures. This Exhibit discusses the changes that the Capital Plan has undergone as the integration process progresses. The resulting plan put forth in the Transmission System Plan (and included for convenience in Table 7 of this Exhibit) includes the investments that are required to maintain or improve the system as evidenced by the recently completed Asset Condition Assessment while optimizing expenditures so as not to unduly burden customers in the future.

1.1 REDUCTIONS DUE TO ASSET REDUNDANCY

Asset redundancy reductions can be realized earlier in the integration process and are the easiest reductions to identify. These assets are considered redundant as HOSSM's assets will be integrated with Hydro One's assets through the integration process to take advantage of synergies. For example, as of February 5, 2018, Hydro One's control room began monitoring and controlling HOSSM assets through the Ontario Grid Control Centre's SCADA and associated systems. Reductions due to asset redundancy include the elimination of capital investments associated with the SCADA system, upgrades, and asset replacement costs. An additional reduction will result as costs of the relocation of a backup control centre, originally planned for by HOSSM, can be avoided given Hydro One's existing infrastructure. Reductions that will continue to be realized year over year are expected to result from Information Technology system scale optimization (e.g. telecommunications, HR, financial etc.), the avoidance of significant costs for improvements to redundant buildings and facilities, leveraging of common Transportation & Work Equipment and upgrades to redundant communication systems (i.e. fibre optic network upgrades). The leveraging of Hydro One's supply chain process and contracts to buy spare parts is also expected to result in further reductions due to the purchasing economies of scale.

<u>Wide Area Network ("WAN") and Fibre Upgrades</u>

The WAN and Fibre Upgrades projects were required in HOSSM's original capital plan as the vintage of the two systems (old technology) was increasingly limiting the ability to meet growing capacity requirements and network needs, and meet current standards such as North American Electric Reliability Corporation ("NERC") reliability standards. The systems also limited remote access to maintenance data and info and therefore impeded operational functionality. These investments are no longer required as HOSSM will be leveraging Hydro One's systems.

The capital investments removed from the capital plan in Table 2 due to asset redundancy are illustrated in Table 3.

Table 3 - Capital Investment Removed from Plan Due to Redundancy with Hydro One (in C$ in thousands)

Investment	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Fibre Optic Network Upgrades	-	(726.8)	(299.1)	-	-	-	(1,638.8)	(1,663.2)	(1,687.9)	(2,329.5)	**(8,345.2)**
SCADA Hardware Refresh	-	-	-	-	-	(1,104.1)	-	-	-	-	**(1,104.1)**
SCADA Asset Management	-	-	-	(596.9)	(1,826.6)	-	-	-	-	-	**(2,423.5)**
Relocation of Backup Control Centre	-	-	-	-	-	-	(2,686.6)	(2,526.5)	-	-	**(5,213.0)**
Radio System Upgrade	-	(765.0)	(780.3)	-	-	-	-	-	-	-	**(1,545.3)**
General SCADA, Telecom, Communications Upgrades	-	-	(156.1)	(159.2)	(162.4)	(165.6)	(163.9)	(166.3)	(168.8)	(171.3)	**(1,313.6)**
Transportation and Work Equipment	-	-	(208.1)	(1,485.7)	(649.5)	(220.8)	(218.5)	(221.8)	(225.1)	(228.4)	**(3,457.8)**
Critical Spare Parts	-	-	(520.2)	(530.6)	(541.2)	-	-	-	-	-	**(1,592.0)**
Total	-	**(1,491.8)**	**(1,963.8)**	**(2,772.4)**	**(3,179.7)**	**(1,490.5)**	**(4,707.7)**	**(4,577.7)**	**(2,081.7)**	**(2,729.2)**	**(24,994.5)**

1.2 PROJECTS REMOVED FROM THE CAPITAL PLAN DUE TO INVESTMENT PRIORITIZATION

Hydro One hired METSCO Energy Solutions to perform a complete in-depth Asset Condition Assessment ("ACA") found in Exhibit B1, Tab 1, Schedule 1, Appendix B. This was the first detailed assessment done on HOSSM's assets in several years. As described in the Transmission System Plan ("TSP"), the results of METSCO's ACA were then incorporated into Hydro One's Asset Risk Assessment ("ARA") model and Investment Planning Process ("IPP") (described in TSP, Chapter 3) and re-evaluated and prioritized using Hydro One's asset assessment criterion. This resulted in some projects being removed from HOSSM's capital investment plan shown in Table 2. These projects will be reconsidered at a later time when the scoring of the assets indicates the asset health indices meet the criteria for capital investment to maintain or improve reliability and meet system capacity and customer needs. The investments removed from the capital plan due to investment prioritization are provided in Table 4.

Table 4 - Projects Removed from the Plan Due to Investment Prioritization (in C$ in thousands)

Investment	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
New Generation Network	-	(510.0)	(520.2)	-	-	-	-	-	-	-	**(1,030.2)**
Mackay Transmission Station Relay Replacements	-	-	-	(193.9)	(298.8)	-	-	-	-	-	**(492.7)**
Security Camera Upgrades at Transmission Stations	-	-	-	-	(541.2)	-	-	-	-	-	**(541.2)**
W23K Line ROW Expansion	-	(153.0)	(156.1)	-	-	-	-	-	-	-	**(309.1)**
Total	**-**	**(663.0)**	**(676.3)**	**(193.9)**	**(840.0)**	**-**	**-**	**-**	**-**	**-**	**(2,373.2)**

1.3 PROJECTS ADJUSTED IN THE CAPITAL PLAN

Considering the asset health indices determined by the METSCO ACA which were then inserted into Hydro One’s ARA model and IPP, there were changes to project scopes and timing as required. In some projects the scope was increased, and in other projects the scope was decreased. Changes in scope or timing could be a result of the asset health index or identified performance issues. A decrease in scope or the rescheduling of a project to a later date in the capital investment plan could be a result of the asset health index or a result of insufficient resources to complete the work as originally planned due to new priority work. Capital investments that had an increase or decrease in funding levels are found in Table 5.

Clergue Transmission Station Upgrade

An example an adjustments made is the Clergue Transmission Station Upgrade including switchgear replacement. This project was originally scheduled to commence in 2022 and be completed in 2025 for a total of $13,007,900. The scope included replacement of the two transformers. While METSCO’s ACA study determined these units to be in the lower part of the “Fair” condition band (51% and 64% Health Indices), subsequent analysis as part of the ARA and IPP processes, identified that the low scores were related to a significant degree of oil leakage. This analysis determined that replacement of the transformer bushing gaskets would prolong the useful lives of the transformers and the transformer replacements were removed from the scope of the investment. The ARA and IPP processes indicated that only the metalclad switchgear and some of the civil infrastructure met the criteria for replacement or upgrade. These items are still in scope and planned for replacement. The project is now scheduled to be completed for a total of $4,800,000 and the work is being completed over a two year period, 2025 and 2026.

Table 5 - Adjustments to Align with Current Capital Investment Plan (in C$ in thousands)

Investment	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Wood Structure Replacements	-	-	(1,590.1)	(1,929.6)	(1,607.4)	(1,766.5)	(2,992.2)	(2,929.8)	(3,032.8)	(3,025.3)	**(18,873.8)**
Sault #3 115kV Line Upgrade	-	-	(772.7)	(3,162.9)	1,761.6	(1,549.1)	-	-	-	-	**(3,723.1)**
Watson Transmission Station Protection Upgrades	-	(1,382.1)	1,100.0	-	-	-	-	-	-	-	**(282.1)**
Clergue Transmission Station Upgrade (includes Switchgear replacement)	-	-	-	-	-	-	(3,770.6)	(1,752.0)	(3,638.4)	(2,846.9)	**(12,007.9)**
Echo River Transmission Station Upgrade	-	-	-	-	1,000.0	-	-	-	-	(378.6)	**621.4**
Third Line Transmission Station - T2 Transformer Replacement	-	(3,372.2)	(2,630.3)	-	-	850.0	1,700.0	1,196.7	-	-	**(2,255.8)**

Investment	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Hollingsworth Transmission Station Protection Upgrades	-	-	-	(248.7)	-	-	-	-	-	500.0	**251.3**
Steelton Transmission Station Upgrade	-	-	-	(2,220.6)	(2,265.0)	-	200.0	960.0	1,160.0	300.0	**(1,865.6)**
New Transmission Station - Replace Goulais & Batchawana	-	-	(485.9)	(68.1)	171.1	(833.8)	5,250.0	-	-	-	**4,033.3**
Third Line Transmission Station Storage Facility Building	-	(714.0)	-	750.0	-	-	-	-	-	-	**36.0**
Land Acquisitions	-	-	(1,040.4)	938.8	-	-	(1,092.5)	(1,058.8)	-	-	**(2,252.9)**
Watson Transmission Station Ring Bus/ Watson TS Upgrade	-	-	-	-	-	-	-	(831.6)	(507.6)	2,529.5	**1,190.3**
Total	**-**	**(5,468.3)**	**(5,419.4)**	**(5,941.1)**	**(939.7)**	**(3,299.4)**	**(705.4)**	**(4,415.5)**	**(6,018.8)**	**(2,921.3)**	**(35,128.8)**

1.4 OTHER ADJUSTMENTS

Other capital investments were removed or added to the capital investment plan for a variety of reasons including but not limited to:

- Costs such as engineering and minor fixed assets were broken out into their own programs and are now included in the consolidation capital and minor fixed assets program costs at a reduced level by leveraging Hydro One resources and supply chain;
- Expenditures for Information Technology systems and building upgrades are no longer required;
- Hydro One inventory is being leveraged;
- The Echo River TS transformer replacement was reprioritized after a specific request from a customer; and
- Northern Avenue TS T1 replacement was added due to the health index of the existing unit.

Table 6 - Other Adjustments (in C$ in thousands)

Investment	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Remove: Engineering - Transmission Lines	-	-	(498.1)	(756.5)	(634.3)	(572.6)	(440.8)	(542.7)	(468.3)	(554.9)	**(4,468.1)**
Remove: Engineering - Transmission Stations	-	-	(641.2)	(423.2)	(569.0)	(351.2)	(433.3)	(344.3)	(431.9)	(358.7)	**(3,552.8)**
Remove: Transmission Line/Station Emergency Work	-	-	(171.7)	(175.1)	(178.6)	(182.2)	(180.3)	(182.9)	(185.7)	(188.4)	**(1,444.9)**
Add: Third Line TS Protection Upgrade	-	-	-	-	-	-	-	-	-	500.0	**500.0**
Remove: Information Technology Refresh - Hardware & Software	-	-	(260.1)	(265.3)	(270.6)	(276.0)	(273.1)	(277.2)	(281.3)	(285.5)	**(2,189.1)**
Remove: Minor Fixed Assets	-	-	(129.0)	(130.2)	(194.8)	(198.7)	(196.7)	(199.6)	(202.5)	(205.6)	**(1,457.0)**
Remove: General Building Upgrades	-	-	(330.3)	(212.2)	(216.5)	(220.8)	(218.5)	(221.8)	(225.1)	(228.4)	**(1,873.5)**
Add: Consolidation Capital & Minor Fixed Assets	-	-	225.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	**1,975.0**
Add: General Plant	-	-	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	**1,000.0**
Remove: Transformer Contingency Plan - Replacements & Spares	-	-	-	-	(1,226.8)	(588.8)	(2,294.3)	(1,928.4)	(2,245.0)	(428.2)	**(8,711.6)**

Investment	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Add: Echo River TS Transformer Replacement	-	-	-	-	-	-	-	1,440.0	3,360.0	-	**4,800.0**
Add: Northern Avenue TS T1 Replacement	-	-	-	-	-	-	-	400.0	950.0	-	**1,350.0**
Total	-	-	**(1,680.4)**	**(1,587.5)**	**(2,915.6)**	**(2,015.3)**	**(3,661.9)**	**(1,481.9)**	**645.2**	**(1,374.7)**	**(14,072.1)**

1.5 EVOLVED CAPITAL INVSTMENT PLAN

After a thorough review of the Capital Investment Plan originally submitted in the Hydro One MAADs application (EB-2016-0050), Table 7 shows the new Capital Investment Plan that is underpinned by a robust ACA followed by rigorous ARA and IPP processes. The IPP process also included many hours of discussion between HOSSM, METSCO and Hydro One planners and management to ensure all aspects of the equipment, system requirements, Regional Planning projects, and customer needs and preferences were appropriately considered.

Table 7 - Current Capital Investment Plan (in C$ in thousands)

Capital Expenditures - Detailed	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Transmission Line Upgrades										
Wood Structure Replacements	4,800	-	-	-	4,000	4,000	4,000	4,000	4,000	**24,800**
Sault #3 Structure & Conductor Replacement	250	3,000	7,000	7,000	-	-	-	-	-	**17,250**
Total Transmission Line Upgrades	**5,050**	**3,000**	**7,000**	**7,000**	**4,000**	**4,000**	**4,000**	**4,000**	**4,000**	**42,050**
Station Upgrades										
Watson TS Protection Upgrade	1,100	-	-	-	-	-	-	-	-	**1,100**
Third Line TS T2 Replacement	-	-	-	850	1,700	2,250	-	-	-	**4,800**
Steelton TS Breaker Upgrade	-	-	-	-	200	960	1,160	-	-	**2,320**
Hollingsworth TS Protection Upgrade	-	-	-	-	-	-	-	500	-	**500**
Clergue TS M/C Switchgear Replacement	-	-	-	-	-	-	-	1,000	3,800	**4,800**
Greenfield Station	-	1,000	2,350	2,500	5,250	-	-	-	-	**11,100**
Echo River TS Transformer Replacement	-	-	-	-	-	1,440	3,360	-	-	**4,800**
Echo River TS Breaker Replacement	-	-	1,000	-	-	-	-	-	-	**1,000**
Third Line TS Protection	-	-	-	-	-	-	-	500	-	**500**

Capital Expenditures - Detailed	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**Total**
Upgrade										
Watson TS Power System Upgrade	-	-	-	-	-	-	1,000	3,700	-	**4,700**
Third Line TS Storage Building	-	750	-	-	-	-	-	-	-	**750**
Steelton TS Line Disconnect Upgrade	-	-	-	-	-	-	-	300	300	**600**
Northern Ave TS T1 Replacement	-	-	-	-	-	400	950	-	-	**1,350**
Total Transmission Station Upgrades	**1,100**	**1,750**	**3,350**	**3,350**	**7,150**	**5,050**	**6,470**	**6,000**	**4,100**	**38,320**
System Equipment										
Consolidation Capital & Minor Fixed Assets	225	250	250	250	250	250	250	250	250	**2,225**
Total System Equipment	**225**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**2,225**
Land and Property Rights										
General Plant	125	125	125	125	125	125	125	125	125	**1,125**
Land Acquisitions	-	2,000	-	-	-	-	-	-	-	**2,000**
Total Land and Property Rights	**125**	**2,125**	**125**	**125**	**125**	**125**	**125**	**125**	**125**	**3,125**
Total	**6,500**	**7,125**	**10,725**	**10,725**	**11,525**	**9,425**	**10,845**	**10,375**	**8,475**	**85,720**

CUSTOMER ENGAGEMENT

1. INTRODUCTION

This Exhibit describes the customer engagement activities Hydro One Sault Ste. Marie ("HOSSM") undertakes to determine its customers' needs and preferences, which help to inform its Transmission System Plan ("TSP"), investment plan and business objectives.

HOSSM's objective is to engage with customers consistently and proactively, leveraging a better understanding of the customer to better meet their needs and improve overall satisfaction with the service they receive. To do this, on a regular basis and as part of its everyday operations, HOSSM engages with customers, to discuss and assist with their needs and preferences. This facilitates the development of an investment plan that is outcome-focused and designed to meet customers' expected level of service.

2. ROUTINE COMMUNICATIONS

HOSSM's asset managers proactively engage with customers to review and coordinate plans for the company's assets, in order to minimize impact on the customer and optimize opportunities for both parties to execute work on their respective, affected facilities. The outcomes of these discussions become an input to HOSSM's transmission system outage scheduling process, which attempts to eliminate multiple outages impacting customer facilities by coordinating activities on the same equipment. HOSSM asset managers also engage with customers as part of the Regional Planning process as documented in Exhibit B1, Tab 1, Schedule 1.

3. 2018 CUSTOMER ENGAGEMENT MEETINGS

HOSSM holds annual Customer Engagement Meetings with its customers. This year, the meetings were also attended by Hydro One representatives. The customers were introduced to the Hydro One Customer Account Executive and Customer Support Officer who will be the customers' main contacts following the operational integration that will occur on October 1, 2018. This was done to assist the customer with their future interactions and communications with Hydro One.

The account executive manages the business side which includes but is not limited to Transmission Connection Agreement issues, future plans, power factor, upgrades, and incentive programs. Account executives meet with customers on a regular basis to ensure that customer needs are identified and discussed, and that action plans are developed to address these needs. If the action plans initiate planning activities that may result in new or modified connection facilities, then the account executives also ensure that customers understand the connection process and related contractual matters, such as feasibility studies, connection cost estimates, and capital cost recovery agreements.

The Customer Support Officer is the contact for operational issues such as post event investigations and customer briefings, power quality investigations, special studies, outage schedules, relay data, system summaries, data sharing (i.e. telemetry), Significant Event Notifications, real time operational issues and processes, and weekly planning reports and newsletters.

Customers indicated that the meetings were valuable to them as they contributed to their understanding of what to expect as the integration between Hydro One and HOSSM progresses. Hydro One and HOSSM intend to continue engaging with customers to receive input for future investment plans and to communicate key information about the transmission system and impacts of investments.

3.1 2018 AGENDAS

The agendas developed this year for the annual Customer Engagement Meetings covered the following topics:

- Organizational Overview and Exchange of Org Charts
- Transmission Connection Agreement
- Other Agreements including Joint Use, Fibre Lease, Licensed Attachments, Radio Agreements, Access Agreements and GIS Data Sharing Agreement
- Customer Delivery Point Performance\Unplanned Outages
    - Transmission Caused Outages
    - Customer Caused Outages
- System Planning Update
    - 2018 Details
    - 5 Year Planned items
    - Planned outages that could impact the Connection
    - Transmission Plans
    - Customer Plans
- Customer Preferences and Needs
- Additional Items
- Review of Action Items

3.2 2018 MEETINGS HELD

HOSSM held the following Customer Engagement Meetings for 2018:

3.2.1 CUSTOMER ENGAGEMENT SESSION #1

Customer Engagement Session #1was held on May 15, 2018 and included representatives from PUC Distribution Inc., HOSSM and Hydro One.

PUC Distribution Inc.

PUC Distribution Inc. is the only subsidiary of PUC Inc., a private company that is wholly owned by the Corporation of the City of Sault Ste. Marie. PUC distributes electricity to residences and businesses within the boundaries of the City of Sault Ste. Marie as well as parts of Prince Township, Dennis Township and the Rankin Reserve. PUC Distribution Inc. is a provincially regulated Local Distribution Company ("LDC") and must comply with requirements issued by the Ontario Energy Board ("OEB") with respect to provision of services.

Minutes of this Customer Engagement Session are found as Attachment #1 to this exhibit.

3.2.2 CUSTOMER ENGAGEMENT SESSION #2

Customer Engagement Session #2 was held on May 16, 2018 and included representatives from Algoma Power Inc., HOSSM and Hydro One.

Algoma Power Inc. ("API")

API has employees working across the Algoma District from Wawa to Thessalon including supervisory, clerical and technical positions, representing a wide-range of skills and a constant commitment to meet their customers' needs. API's distribution system has grown to over 1800 kilometres of lines in a service area of approximately 14,200 square kilometers serving a diverse range of customers. API has a long and proud history of electricity distribution and service to customers in this area for over 100 years.

Minutes of this Customer Engagement Session are found as Attachment #2 to this exhibit.

3.2.3 CUSTOMER ENGAGEMENT SESSION #3

Customer Engagement Session #3 was held on May 16, 2018 and included representatives from Essar Steel Algoma, HOSSM and Hydro One.

Essar Steel Algoma

Algoma (formerly Algoma Steel; Essar Steel Algoma) is an integrated primary steel producer located on the St. Mary's River in Sault Ste. Marie. Algoma manufactures hot and cold rolled steel products including sheet and plate with a production capacity of four million tons. Its products are sold in Canada and the United States as well as overseas. Algoma Steel was founded in 1902. In April 2007, Algoma Steel was purchased by India's Essar Group, continuing operations as a subsidiary known as Essar Steel Algoma Inc.

Minutes of this Customer Engagement Session are found as Attachment #3 to this exhibit.

3.2.4 CUSTOMER ENGAGEMENT SESSION #4

Customer Engagement Session #4 was held on May 17, 2018 and included representatives from Brookfield Renewable Energy Group, HOSSM and Hydro One.

Brookfield Renewable Energy Group

Brookfield Renewable is a global renewable power producer that values active local involvement in the communities in which it operates. In the Algoma District, it owns and operates 16 hydropower generating stations and 1 wind farm.

Minutes of this Customer Engagement Session are found as Attachment #4 to this exhibit.

Hydro One SSM & PUC
Customer Engagement Meeting Minutes

Date: May 15, 2018
Time: 3:00 PM
Location: PUC Head Office

Attendees

Hydro One SSM	PUC
Brad Colden - HOSSM	Claudio Stefano
Steve Dale – HOSSM	Mark Faught
Kim Irvine – HOSSM	Al Cannard
Kevin Lewis – HOSSM	Rob Harten
John Blackburn – HONI	Mitch Paradis
Maxine Cooper - HONI	
Steve Ritchie – HONI	

1. Introductions
Steve Dale began meeting by introducing HONI attendees and starting us off with round table introductions.

2. Review and approval of meeting agenda
Steve asked everyone to quickly review the agenda to ensure all topics to be discussed were addressed. He noted that any additional items could be brought up in the Additional Items section (agenda #11). No additional items were brought up at this time.

3. Organizational Overview and exchange of org charts
- Hydro One organization and company status
Kevin Lewis discussed our organizational chart and gave a high level description of our organization plan. We will be a stand-alone entity until 2023 and we anticipate no changes to performance for our customers.

4. Approval of last Meeting Minutes – *2017 Minutes were reviewed and approved by the group.*

5. Transmission Connection Agreement

   a) TCA – Schedule
   TCA is currently with Bob Coghlan to be updated before signing off. Updates will include a newer format, OEB changes to the TSC (NERC stds 005) and other revisions. Contact info is to be kept up to date going forward. The last TCA was signed off about 15 years ago.
   John Blackburn noted that he will be available to assist PUC with updates/changes to the TCA going forward.
   Steve Ritchie can also assist with follow up services, customer briefings, relay data, planning reports etc.
   *Claudio has requested to be added to outage plan distribution list. *Action created**

6. Other Agreements

   a) Joint Use

      i. Utility (in Draft)

         - HOSSM and PUC need to continue to draft the 2 separate agreements

      Current Joint Use Agreement expires Dec. 2019.
      *Rob Harten will sent draft copy to Steve Dale *Action created**

   b) GIS Data Sharing Agreement – Expires Dec 31, 2018

      PUC has stated that they still find this data useful as a planning tool and would appreciate having their access continue.
      HOSSM is looking to adopt HONI practices.
      *Rob Harten will work on renewing agreement as it will expire this year. *Action created**

7. Customer Delivery Point Performance\Forced Outages

A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more of HOSSM's components causing load loss. Interruptions caused by HOSSM customers are recorded but not charged against the reliability performance for the customer initiating the interruption, but are charged against the reliability performance for other interrupted customers.

<u>Outlier Triggers</u>

Performance Measures	**Delivery Point Performance Standards** (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		**>15 to 40MW**		**>40 to 80MW**		**>80MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

When the three year rolling average of DP performance falls below the minimum standard of performance ("Outlier"), HOSSM will initiate technical and financial evaluations to determine root cause and if any remedial action is required.

2017-2015 (3 year rolling average) reliability performance

Delivery Point	**3Year Average Interruption Duration (2015-2017) (min)**	**3Year Average Interruption Frequency (2015-2017)**	**2017 Interruption Duration (min)**	**2017 Interruption Frequency**
GL1TA/GL2TA	**0.00**	**0.00**	**0**	**0**
GL1SM/GL2SM	**15.6**	**0.33**	**0**	**0**

a) Transmission Caused Outages – None

b) Market Participants Caused Outages – None

8. System planning update

Steve Dale reviewed the following non impactive projects with PUC

a) 2018 Details

i. P21G Structure Replacement – 35 structures in 2018

ii. Algoma 1 Str 28, Algoma 3 Str 32, 33 replacement

iii. DA Watson TS, 34.5kV Protection Upgrade –

b) 5 Year Planned items

i. Soo #3 Reconductor and restructure from Goulais TS to Mackay TS

ii. Batchawana – Goulais TS Greenfield Project

9. Planned outages that could impact the Connection.

a) Transmission Plans

i. HOSSM Outage Schedule
P21G will be out of service for the majority of the summer.

b) Market Participant Plans

i. Maintenance and Downtime Schedule
Two maintenance outages for PUC are planned
- Transfer Trip Project – first half, starting last week of May, portions to be worked on every couple of weeks through the summer
- Breaker/Maintenance Project – Beginning end of July/August. We will coordinate this with HOSSM cap bank project

10. Customer Preferences and Needs
John Blackburn – *My goal is to push for resources and results for our customers. Both John and Steve Ritchie can help communicate any issues and prioritize challenges for PUC.*

11. Additional Items
a) Update on status for Energy Storage project
8 additional storage banks are being evaluated
b) Use of PUC connection to supply Northern Ave 12kV circuit in contingency situation
HOSSM is hoping to put a switch in as a contingency plan. Steve will set up a meeting with PUC to discuss this option further. *Action created*
c) OGCC is now the controlling authority on a 24/7 basis as of Feb 5th.
d) Load Forecasts
*Steve requested PUC supply load forecast *Action created**
e) PUC usually plans capital in the Fall – Q2
f) HONI - Planning will visit in the Fall
- *Look at 12-18 months out*
- *90 day window for IESO*
- *May use additional crews from south to mitigate customer impact*

12. Review Action Items (closed and open)

Action No	Agenda Item	Subject	Action	Assigned To	Due Date
2016-001	6	TCA	Updated TCA sent to PUC	Rob Harten/Mitch Paradis	June 29/2018
2016-005	11	UFLS De-registration	Provide schedule and notification when UFLS project completed	Mitch Paradis	Require update
2016-006	11	TT Receive	Open issue, PUC needs to install facilities to receive A&B TT signals from HOSSM	Mitch Paradis	Require update
2017-01	9	Schedule Capital Plan meeting	Planning details of med/long term projects which may have synergies	Brad Colden	OPEN
2018-01	*5a*	*Outage Distribution List*	*Claudio has requested to be added to the outage distribution list*	*Steve Dale*	*OPEN*
2018-02	*6a*	*Joint Use Agreement*	*Rob Harten will send draft copy to Steve Dale for review*	*Rob Harten*	*OPEN*
2018-03	*6b*	*GIS Data Sharing Agreement*	*Rob Harten will work on renewing agreement as it will expire this year*	*Rob Harten*	*OPEN*
2018-04	*11b*	*PUC connection to supply Northern Ave 12kV circuit*	*Steve Dale to set up a meeting with PUC to discuss this option further*	*Steve Dale*	*OPEN*
2018-05	*11d*	*Supply Load Forecast*	*Steve requested load forecast from PUC*	*Mitch Paradis*	*OPEN*

Meeting adjourned: 4:25pm

Hydro One SSM & API
Customer Engagement Meeting Minutes

Date: May 16, 2018
Time: 9AM
Location: Algoma Power Office

Attendees

Hydro One SSM	API
Brad Colden - HOSSM	Dan Richards
Steve Dale – HOSSM	Mike Degilio
Kevin Lewis – HOSSM	Jen Rose
Kim Irvine – HOSSM	Phil Johnson
John Blackburn – HONI	
Steve Ritchie – HONI	
Maxine Cooper - HONI	

1. Introductions
   Steve Dale began meeting by introducing HONI attendees and starting us off with round table introductions.

2. Review and approval of meeting agenda
   Steve asked everyone to quickly review the agenda to ensure all topics to be discussed were addressed. He noted that any additional items could be brought up in the Additional Items section (agenda #11). No additional items were brought up at this time.

3. Organizational overview and exchange of org charts
   - Hydro One organization and company status
   Kevin Lewis discussed our integration process and gave a high level description of our organization plan. Operational transition to Hydro One still planned for Oct 1st. We will be a stand-alone entity until 2023 and we anticipate no changes to performance for our customers. API will be notified on who points of contact from HONI will be going forward.

4. Transmission Connection Agreement

   a) Review of Schedule

      i. Operations Contacts – *Schedule A&D to be updated with new contacts and sent to Jen for approval before agreement is finalized.*

5. Other Agreements
   As of Oct. 1st, HOSSM plans to adopt HONI policies and practices, but this should not impede on customer business. There will be new contacts and resources made available to API. (John Blackburn & Steve Ritchie)
   a) Joint Use – In effect until Dec 31, 2018
   b) Access Agreements – Names updated for 2018

6. Customer Delivery Point Performance\Unplanned Outages
   - Steve Dale reviewed outage charts with the group. We are in good standing with

OEB limits but will still strive to improve where possible.
- Steve Dale provided API with copies of Customer Briefings for the following outages where required. Going forward, when requested from HONI, customer briefings will be prepared within a 10 day window. (provided upon customer request)
- Customer briefings will also be stored on website for customers to view. History of past briefings will also be available there.

Outlier Triggers

Performance Measures	Delivery Point Performance Standards (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		>15 to 40MW		>40 to 80MW		>80MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

When the three year rolling average of DP performance falls below the minimum standard of performance ("Outlier"), HOSSM will initiate evaluations to determine root cause and if any remedial action is required.

API 2017-2015 (3 year rolling average) reliability performance

Delivery Point	3Year Average Interruption Duration (2015-2017) (min)	3Year Average Interruption Frequency (2015-2017)	2017 Interruption Duration (min)	2017 Interruption Frequency
Northern Ave 34.5kV	0	0.33	0	0
Northern Ave 12kV	0	0	0	0
Echo River	30.33	1.00	84	2
Batchawana	185.67	2.00	0	0
Goulais	106.33	2.00	0	0
Mackay	0	0	0	0
Andrews	0	0.33	0	0
Watson	10.33	0.33	31*	1*
No.4 Circuit	178.00	2.00	3*	1*

a) Transmission Caused Outages

   i. June 11 – P22G trips, trees outside of ROW on circuit

   ii. Sept 13 – Inadvertent trip, Wawa area islanding - Internal investigation done to determine root cause. *GE employee caused.*

   iii. Sept 24 – CS020 trips and remains open on one phase - Manufacturer tech rep mitigated problem May 14, 2018. *Weather related*

b) API System Unplanned Interruptions

   i. Jan 23, 2017 – CS020 trips on #2 Bruce Mines protection

   ii. April 9, 2017 – T1 fuses at Goulais TS, lightening in local area

   iii. May 2, 2017 – CB385 trips at Northern Ave. Unknown cause

7. System planning update

   a) 2018 Details
      - P21G Structure Replacement – 35 structures in 2018
      - Algoma 1 Str 28, Algoma 3 Str 32 & Str 33 replacement
      - DA Watson TS, 34.5 kV Protection Upgrade

   b) 5 Year Planned items
      - Sault 3 reconductor and restructure from Goulais TS to Mackay TS
      Feasibility study to take place over 3 years
      - Batchawana TS / Goulais TS Greenfield Project
      API doing study – out for tender.
      Completion 2018

8. Planned outages that could impact the connections.
   - Going forward API will have access to a weekly customized report for discussion (sent out on Thursdays)
   - Hydro One interested in API's schedule to work collaboratively
   - bundle work to mitigate SAIDI and SAIFI

   a. Transmission Plans

      i. Hydro One SSM Outage Schedule

   b. API Plans

      i. Maintenance and Downtime Schedule
         - API will advise of customer outages (mines)

- If dates are unknown, it can be a place holder in the developing schedule as a reminder to discuss closer to the time.
- 2 SCADA systems at OGCC will be integrated in the Fall. Steve Ritchie invited API to visit Barrie to see OGCC.
- API is looking into an operating role. Communication is an issue (data). They will require ICCP link. API to work with Steve Ritchie on this.

9. Customer Preferences and Needs
- Hydro One wants to understand API's needs and preferences (ex. One longer outage or multiple short outages when possible)
- There are 3 customer briefing options available (formal, email, phone)
*- Steve Ritchie will add an API group list to the SANS distribution list *Action created*
- Weekly customer newsletter is available as well.
- John has requested "formal, normal, and casual contacts from API for future communication purposes

10. Additional Items
    - OGCC is now the controlling authority on a 24/7 basis
    - Outage coordination between HOSSM and API *- Steve R mentioned that planning relationship is important. You will get to know HONI planners for outages and coordination.*
    - Response letter addressing DP concerns
    - Limer TS project update *– John will be point of contact for API*
    - Hold Off process for underbuild *– OGCC should be calling into the Control Room rather than field staff communicating with OGCC. Steve Ritchie will make sure OGCC is clear on the process for contacting us for hold offs.* *Action created*
    - Load Forecasts – *Mike will send updated list to Steve Dale and John Blackburn *Action created**
    - Echo River – Redundancy issue – Contingency concern
      - Jenn showed interest in getting Echo River Project put into a 5 year plan. It is a critical item for API.
      - Metsco should be made aware that API has concerns regarding Echo River when study is taking place
      - Cost benefit analysis has been done by API which they will share with HONI for investment planning process.
      *- John suggested a meeting be set up to discuss these items further. *Action created**

11. Review Action Items

Action No	Agenda Item	Subject	Action	Assigned To	Due Date
1	4b	Update TCA Operations Contacts	Add Jen to contacts and review that all other contacts are accurate	Steve Dale	Ongoing
2	5a	Where does Joint Use agreement reside?	Dan Richards will provide a copy to Brad Colden	Dan Richards	Expires Dec 31,2018
4	5c	Possible land access agreement to be discussed for API to have access to Echo River.	Jen will send contact of who they are working with from Hydro One.	Jen Rose	Open
6	9	Exchange of GIS information and communicating LIDAR work being done could be mutually beneficial	Currently working with HONI to investigate progress of HONI implementation	Steve Dale	Open
9		Outage planning	Moving forward API will be receiving all HONI normal correspondence	Brad Colden	Open
9		*SANS Distribution List*	*Add API group to the SANS Distribution List*	*Steve Ritchie*	*OPEN*
10		*Echo River – Contingency concern*	*John requested a meeting be set up with API to discuss expectations and concerns*	*API*	*OPEN*
10		*Hold off process*	*Steve Ritchie will communicate proper process to OGCC to make sure everyone is clear*	*Steve Ritchie*	*OPEN*

10		*Load Forecast*	*Send updated list to Steve Dale and John Blackburn*	*Mike Gegilio*	*OPEN*
		API Org Chart	*To be emailed to Steve Dale*	*Mike Gegilio*	*OPEN*

12. Schedule next meeting

13. Adjourn Meeting

Time:

Hydro One SSM (HOSSM) & ESSAR Algoma
Customer Engagement Meeting Minutes

Date: May 16, 2018
Time: 3:00PM
Location: Algoma Board Room – 105 West Street – Admin Bldg

Attendees

Hydro One SSM	Algoma
Brad Colden – HOSSM	Denis Cesarin
Steve Dale – HOSSM	John Jones
Kim Irvine – HOSSM	Mark Negalo
Kevin Lewis –HOSSM	
John Blackburn – HONI	
Steve Ritchie – HONI	
Maxine Cooper - HONI	

1. Introductions
   Steve Dale started meeting with a round table of introductions

2. Review and approval of meeting agenda
   Agenda was reviewed and approved by the group.

3. Organizational Overview and exchange of org charts
   - Hydro One organization and company status
   Kevin Lewis spoke to our integration process into the larger Hydro One but assured Algoma that assets are to be maintained locally. Algoma will have more dedicated resources available moving forward.

4. Approval of last Meeting Minutes
   Minutes from 2017 meeting were reviewed and approved by the group.

5. Transmission Connection Agreement

   a) TCA – Understand the requirement for 2 separate TCAs to be created
   -Transmission
   -Generation

   b) Connection Status for LSP
   - LSP should be connected by the end of June. Most of the engineering is complete. Algoma is still waiting on cable to be delivered.
   - Working on protections and SCADA.

6. System planning update

   a) 2018 Details
   - P21G Structure Replacement – 35 structures in 2018
   - Algoma 1 Str 28, Algoma 3 Str 32 & Str 33 replacement

This could have an impact on Algoma contingency wise.
- DA Watson TS, 34.5 kV Protection Upgrade

b) 5 Year Planned items

- Sault 3 reconductor and restructure from Goulais TS to Mackay TS
- Batchawana TS / Goulais TS Greenfield Project

7. Customer Delivery Point Performance\Forced Outages
- Production system is very sensitive to power quality and voltage fluctuations.
- Since 230kv upgrades, reliability has been a lot better.
- John Blackburn can help with power factor, VARS, etc.

<u>Outlier Triggers</u>

Performance Measures	**Delivery Point Performance Standards** (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		**>15 to 40MW**		**>40 to 80MW**		**>80MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

When the three year rolling average of DP performance falls below the minimum standard of performance ("Outlier"), HOSSM will initiate evaluations to determine root cause and if any remedial action is required.

2017-2015 (3 year rolling average) reliability performance

Delivery Point	**3Year Average Interruption Duration (2015-2017) (min)**	**3Year Average Interruption Frequency (2015-2017)**	**2017 Interruption Duration (min)**	**2017 Interruption Frequency**
ESAI (301T1, 301T2, 301T3)	**0.00**	**0.00**	**0**	**0**
ESAI (10T1)	**0.00**	**0.00**	**0**	**0**
ESAI (T6&T7)	**0.00**	**0.00**	**0**	**0**
ESAI Wallace Terrace	**0.00**	**0.00**	**0**	**0**

a) Transmission caused outages – None

b) ESSAR Algoma caused outages – None

8. Planned outages that could impact the Connection.

A) Transmission Plans
- HOSSM Outage Schedule

B) Algoma Plans
- Maintenance and Downtime Schedule

- May 28th 7 day shut down planned
*- Algoma has agreed to send us their outage list *Action created**
- Algoma plan usually developed by February annually

230kv supply *for electric arc furnaces to be installed in the future (possibly within the next 10 years) and flicker control. Algoma would like to keep on record for future discussions.*

Chromium – 500MW

- Land set aside. Not known at this time if it will materialize
- Studies on capacity and routing to be evaluated by John Blackburn re: upgrades, new lines.

9. Customer Preferences and Needs

- Hydro One wants to understand ESSAR Algoma's needs and preferences (ex. One longer outage or multiple short outages when possible)
- There are 3 customer briefing options available (formal, email, phone)
- We are working to align with customers

10. Additional Items

- UFLS schemes, are Algoma moving forward with these?
  Implementation of UFLS schemes completed
- Teneris would like own supply.
  - Project for embedded Gx, looking for guidance. Algoma will discuss with Tenaris to better understand what they want. John Blackburn is available to help with this.
- Relationship with OGCC – Steve Ritchie is contact person for:
  Post events, customer briefs, data sharing, SENS (what happened on grid), PQ issues
  - *A visit to Barrie could be beneficial to load dispatchers*

11. Review Action Items

Action No	Agenda Item	Subject	Action	Assigned To	Due Date
2016-001	3	Org Chart	Essar to supply HOSSM with org chart	*Mark Nogalo*	Open
2017-001	6cii	LSP	Algoma will notify HOSSM in conjunction with the IESO regarding SIA.	Gord Lees	12 to 18 months
2017-002	6ciii	LSP	Steve Dale to look at the capacity improvements that result from the Sault No. 3 reconductoring	Steve Dale	Ongoing
2017-005	11	Emergency contacts and tour of Algoma	Hydro One to tour Algoma to understand demands in the case of an emergency	*Brad to coordinate. Controllers to tour Algoma. S4 presentation can be arranged*	Open
2017-006		Disturbance Monitoring	Don to provide a sample of sag that occurred to Hydro One	Don Kennedy	Open
2017-007	10.b	Algoma Planned Outage Schedule	*Vic from Hydro One SSM to attend meetings with OGCC planning to coordinate outage plans. Brad to discuss with Vic.*	Brad	Open

12. Schedule next meeting

Future meetings will be scheduled by John Blackburn

13. Adjourn Meeting – *4:25pm*

Hydro One SSM & Brookfield
Customer Engagement Meeting Minutes

Date: May 17, 2018
Time: 8:30AM
Location: Clergue Rm, Brookfield Work Center, SSM ON

Attendees

Hydro One SSM	Brookfield
Brad Colden - HOSSM	Brandon Lismans
Steve Dale – HOSSM	Claude Samson
Kevin Lewis – HOSSM	Bruce Welbourne
Kim Irvine – HOSSM	Dave Hurd
John Blackburn – HONI	Kevin Healy
Steve Ritchie – HONI	DJ Boston
Maxine Cooper - HONI	Janis Gartshore
	Andy Punkari

1. Introductions
   Steve Dale began meeting by introducing HONI attendees and starting us off with round table introductions.

2. Review and approval of meeting agenda
   The agenda was distributed to all and reviewed for content. The agenda was adopted as presented.

3. Organizational overview and exchange of org charts
   - Hydro One organization and company status
   Kevin Lewis discussed our integration process and gave a high level description of our organizational plan. Operational transition to Hydro One still planned for Oct 1st. We will be a stand-alone entity until 2023 and we anticipate no changes to performance for our customers.

4. Approval of last meeting minutes
   Last meeting minutes were distributed and reviewed as a group for accuracy. Minutes were approved

5. Transmission Connection Agreement

   a) Schedule updates to reflect current projects: Gartshore GS G1 upgrade, Steephill GS circuit switcher installation, Andrews GS T3 replacement, Clergue GS T1/G1 and T2/G2 protections replacement
   TCA will be updated with John Blackburn moving forward. Schedule A is to be updated and sent to Bruce Welbourne within 2 weeks.

   b) Operations Contacts
   Bruce will update contact list and send to Steve Dale *Action created*

6. Agreements
   Schedule A is very important to operations. Must be kept up to date. Special requirements should be noted.

Hydro One Sault Ste. Marie has identified the following agreements:

Agreement Name	Expires	Notes
Fiber Lease	2018	Updated on June 30, 2015 for a 3 year term
Licensed Attachment (Fiber)	2017	3 year term from 2009–2012 with an option of a 5 year extension.
Unaccompanied Access Agreements	June 2020	Requires all BRP employees that access HOSSM sites without an escort to have completed the BRP CIP-004 PRA program to meet the requirements of section 5 (“Security Protocol for Unaccompanied Access”) of this agreement.
Radio Agreement	June 2012 w/ automatic annual renewal period of 1 year	Termination of the agreement requires 60 day(s) notice prior to June 30th of each year.

7. Transmission Outages

-Steve Dale reviewed the 7 interruptions that effected Brookfield.

-Steve Ritchie mentioned there will be a 10 day turnaround for customer briefings moving forward. A report can be requested from the customer on any interruption. Three types of reports are available depending on need (formal, email, phone)

i. July 30, 2017 – Mission Circuit Interruption, lightning in area

ii. Aug 12, 2017 – Limer 44kV Line Interruption, protections responded to a voltage imbalance on the 12kV side of the station

iii. Sept 10, 2017 – Wawa area interruption, a three phase to ground fault was seen outside of the HOSSM system
- no explanation received for this outage. Cause unknown.

iv. Sept 13, 2017 – Wawa area interruption, inadvertent trip
Internal investigation done to determine root cause
P&C and GE working on protections. GE rep accidently caused outage.

v. Sept 26, 2017 – Hollingsworth 115kV Line Interruption, line to ground fault seen outside of HOSSM system
- no explanation received for this outage. Cause unknown.

vi. October 24, 2017 – Wawa area interruption, tree on 34.5kV feeder at DA Watson TS
- tree was inside TS. Weather related outage.

vii. December 5, 2017 – #2 McPhail 34.5kV Line Interruption, tree on 34.5 kV line. Human intervention
- Tree fell on line. Brookfield investigated and discovered “Joe Public” cutting tree down for Christmas caused outage. Brookfield worked

with the OPP on this and will be adding more danger signage.

8. System Planning Update
   Steve Dale reviewed our upcoming capital plan projects. Not to affect Brookfield.

   a. 2018 Details
      - P21G Structure Replacement – 35 structures in 2018
      - Algoma 1 Str 28, Algoma 3 Str 32 & Str 33 replacement
      - DA Watson TS, 34.5 kV Protection Upgrade

   b. 5 Year Planned items
      - Sault 3 reconductor and restructure from Goulais TS to Mackay TS
      - Batchawana TS / Goulais TS Greenfield Project

9. Planned outages that could impact the connections

   i. Transmission Plans - Hydro One SSM Outage Schedule
      Provided in handout

   ii. Brookfield Plans - Maintenance and Downtime Schedule
      Brookfield will share outage schedule to suit common goal with minimal impact.

10. Customer Preferences and Needs
    John Blackburn wants to understand Brookfield's needs and preferences (ex. One longer outage or multiple short outages when possible) and mentioned several ways that he and Steve Ritchie can be assets to Brookfield moving forward.
    - Help HONI manage your expectations though open communication and accommodating
    - Weekly customer newsletter is sent out every Thursday to generate discussion.
    - Reciprocal approach to eliminate duplicative outages
    - Work to mitigate impact to generators

11. Additional Items
    - OGCC is now the controlling authority on a 24/7 basis
      Customer access numbers will be provided to Brookfield for direct contact to OGCC.
    - Increase in switching staff
      Hydro One looking to employ two additional Lineman within the year to assist with switching.
    - Status of work done in regards to the ferroresonance issue in Hollingsworth area
      Issue with transformer feed
      - Possibly going to eliminate transformer and use generator for backup
      - Grounding study to take place
      - Hollingsworth TS information to be sent to Steve Ritchie to notify OGCC
    - *Wind Farm Radios*
      - Recently the radios in Wind Farm are failing. Switching to analog but is starting to be an issue. -- Hand held to hand held and trucks

- Kevin Lewis will take this concern under advisement and look into whether HOSSM plans to update to digital.
- Steve Ritchie will look into who manages this issue at OGCC and how it is applied.

- *Lake Superior Link (East West Tie)*
  - Will outages affect Brookfield
  - Still in front of OEB
  - Expedited outages with more crews are planned

12. Review Action Items

Action No	Agenda Item	Subject	Action	Assigned To	Due Date
2016-002	6a	Connection facilities	Update on Steephill Connection upgrades to reduce impact on HOSSM market participant. *Ordering equipment. Having issues with real estate.*	Ralph Stefano	Planned for next year. Open
2017-003	6	Operational Contacts - Schedule A	Steve Dale to send an updated electronic version of Schedule A to Bruce W.	Steve Dale Bruce Welbourne	Open
2017-005	9b	Outage Planning	Steve Dale will set up a December planning meeting with Brookfield.	Steve Dale	Open
2018-01	*5b*	*Operations Contacts*	*Bruce will update contact list and send to Steve Dale*	*Bruce Welbourne*	*OPEN*
		Outage Plan	*Antione to provide outage plan to Steve Ritchie and Steve Dale*	*Antoine*	*OPEN*

13. Schedule next meeting
    - Future meetings will be scheduled by John Blackburn

14. Adjourn Meeting

Time: 10:02am

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	**Provide a list of customer needs and preferences identified through each engagement activity**	**Actions taken to respond to identified needs and preferences. If no action was taken, explain why.**
Annual Customer Engagement Meetings	Fault values, outage explanations, Transmission Connection Agreement updates, general customer issues, specific system upgrade requests (i.e. Algoma Power Inc. contingency concern for Echo River TS)	Deliverables provided. Subsequent meetings arranged to further discuss outstanding issues. Identified system concerns discussed (i.e. Echo River Transformer Replacement was reviewed in the investment planning process and is identified on investment plan.
Support for System Impact Assessment and Connection Impact Assessment development for customer projects	Fault values, protection coordination, system impact, feasibility studies	Support by Hydro One Sault Ste. Marie (“HOSSM”) was provided in a timely manner as required
Ongoing communications	Discussions of upcoming requirements, short and long-term planned outages, future plans that will impact load	Customer planned outages reviewed and coordinated with HOSSM's outage schedule for efficiency and to limit outages. Subsequent meetings arranged as required.

PERFORMANCE MEASUREMENT AND CONTINUOUS IMPROVEMENT

1. INTRODUCTION

Hydro One Sault Ste. Marie ("HOSSM") is committed to demonstrating continuous improvement in the transmission of electricity that is at a level expected by our customers. To measure the performance to this commitment, HOSSM has developed a balanced scorecard that is aligned with the OEB's Renewed Regulatory Framework ("RRF") and is substantially aligned with Hydro One's transmission scorecard. The scorecard combined with HOSSM's Key Performance Indicators ("KPIs") program will aid in identifying areas of opportunity to enhance the effectiveness of HOSSM's performance management program and will help to ensure that the objectives and goals of the company are being managed to create additional value for the rate payer. HOSSM maintains and tracks measures across the company to align work execution in each line of business with the corporate drivers.

1.1 KEY PERFORMANCE INDICATORS

HOSSM is committed to building a strong performance management culture and is committed to continuous improvement and excellence in all parts of the business. HOSSM manages a safe, reliable, cost efficient and environmentally responsible transmission system and has been committed to continuous improvement of critical areas of the business through the establishment of annual KPIs to measure and manage performance. KPIs evolve and are refined over time to ensure that they continue to drive and effectively capture the impact of incremental efficiency improvements. In certain cases, HOSSM has developed a KPI to track the successful implementation of a new program or practice. Some of these KPIs are then replaced with a more current KPI that has been developed to realize efficiencies in another area of opportunity in the company. For example a metric may be used to track the outcome of a newly implemented process to ensure it is driving the desired results.

HOSSM's KPIs have traditionally been separated into four corporate drivers:

- Excellence in Health, Safety, Security and Environment ("HSSE");
  This objective is to the benefit of the company and customers by tracking health, safety, security and environment related incidents that may affect productivity and work accomplishment. Incidents can be costly as they initiate other processes such as investigation and legal review. Incidents of this nature can also have a great effect on staff personally through illness, injury and rehabilitation.
- Continued Value Creation;
  This performance objective measures the company's success in continued innovation in work execution processes and practices to improve the reliability and performance of the transmission system and complete work within prudent budget constraints.
- Risk Management;
  Management of key reliability, operational and compliance risk increases quality of service and mitigates risk of penalties associated with non-compliance and poor performance.
- Investment in our People
  The establishment of individual development plans and leadership programs is important to empower staff with the appropriate tools and resources to build effective teams, increase competence, efficiency, and productivity. This will benefit HOSSM and the customer.

Certain KPIs have been adopted as metrics on the newly proposed corporate scorecard, described in Section 1.2 of this exhibit. Examples of corporate KPIs are described in Section 1.4 of this exhibit.

1.2 PROPOSED SCORECARD

HOSSM is committed to continuous improvement in productivity and efficiency to demonstrate value to customers. To measure the success of this commitment, HOSSM has aligned its planning, execution and reporting functions around performance outcomes that are consistent with the OEB's Renewed Regulatory Framework ("RRF") outcomes. The RRF outcomes are:

- Customer Focus;
- Operational Effectiveness;
- Public Policy Responsiveness; and
- Financial Performance.

HOSSM's performance in achieving these outcomes is reflected in its proposed Transmission Scorecard (see Figure 5). Metrics have been drawn from HOSSM's KPIs, scorecards, Hydro One metrics and the OEB's *Performance Measurement for Electricity Distributors: A Scorecard Approach* report. The measures were also informed by the OEB's guidance in the Handbook for Utility Rate Applications[1] ("Handbook") by reflecting the following key considerations:

- A focus on strategy and results, not activities;
- The need to demonstrate continuous improvement;
- Outcomes that are demonstrated to be of value to customers; and

[1] Ontario Energy Board, Handbook for Utility Rate Applications, October 13, 2016, p.16

- Performance metrics that accurately measure whether outcomes are being achieved, and that include stretch goals to demonstrate enhanced effectiveness and continuous improvement.

1.3 EVOLUTION OF KPIS AND THE HOSSM SCORECARD

HOSSM is committed to continuing to identifying key factors that align with the RRF principles and incorporating them into the performance management system as KPIs. Direct links can be drawn between major corporate drivers and measurable objectives that will translate into tangible performance measures. HOSSM believes these will also align with the requirements of the balanced scorecard and further drive value for the customer. HOSSM has further supported these objectives by connecting them with direct work groups, individual employee goals and the compensation program.

As stated in EB-2016-0050, "commencing in 2017 and 2018, HOSSM and Hydro One will begin to identify areas where longer-term operational synergies and savings may be achieved"[2] as a result of consolidation. The outcome of this work is reflected in the proposed scorecard.

[2] EB-2016-0050 - Exhibit A, Tab 2, Schedule 1, Page 1

1.4 KEY PERFORMANCE INDICATORS PEFORMANCE

Some of the KPIs that HOSSM has been tracking are shown in Table 1.

Table 1 - HOSSM KPIs

Corporate Driver	Measurement
HSSE	High Risk Incidents (determined per HOSSM's Managed System)
	Preventable Motor Vehicle Accidents
	Safe Work Observations (% of total planned)
Continued Value Creation	OM&A at approved levels (actual as % of budget)
Risk Management	Self-Reports of Non-Compliance with NERC Standards
	Job Plan Quality Reviews (% of total planned)
Investment in our People	No measurement at this time

1.4.1 HEALTH, SAFETY, SECURITY AND ENVIRONMENT ("HSSE")

HOSSM has a number of initiatives and processes in place to provide indicators that ensure shortfalls and deficiencies in the HSSE program are identified early and corrected proactively. The HOSSM leadership team develops annual HSSE initiatives and implements an execution plan to achieve desired goals. Progress is reported quarterly to all staff at Quarterly Safety Meetings and presented monthly to management. HOSSM commits to continue to reinforce and promote safe work practices and management, and team commitment to HSSE within the organization and the public.

High Risk Incidents

High risk incidents include but are not limited to reported near miss incidents, personal injury, equipment damage, environmental incidents and public incidents. After an HSSE accident or incident event occurs, a reporting and investigation form is completed that provides definitions to assist the user to assess the incident and appropriate reporting.

The incidents are deemed high risk if they meet the criteria and documented in HOSSM's Managed System.

HOSSM has had no high risk incidents in the past five years and expects to maintain this record.

Preventable Motor Vehicle Accidents

Another KPI used by HOSSM is recordable licenced fleet motor vehicle incident rate for on-road vehicles only, where the collision results in over $5,000 damage or a recordable injury. When a motor vehicle is involved, an "On Road Accident MVA" form is completed to assist in determining if the incident is considered a high Maximum Reasonable Potential for Harm ("MRPH") incident. All incidents are reviewed with staff and discussed at the quarterly safety meeting.

This measure has been formally tracked since the end of 2016 as part of the integration process to align with Hydro One's measures. The data for the years previous to 2017 were extracted from other documentation and therefore this metric currently does not include the number of kilometers driven like Hydro One's measure. The results for this metric are shown in Figure 1.

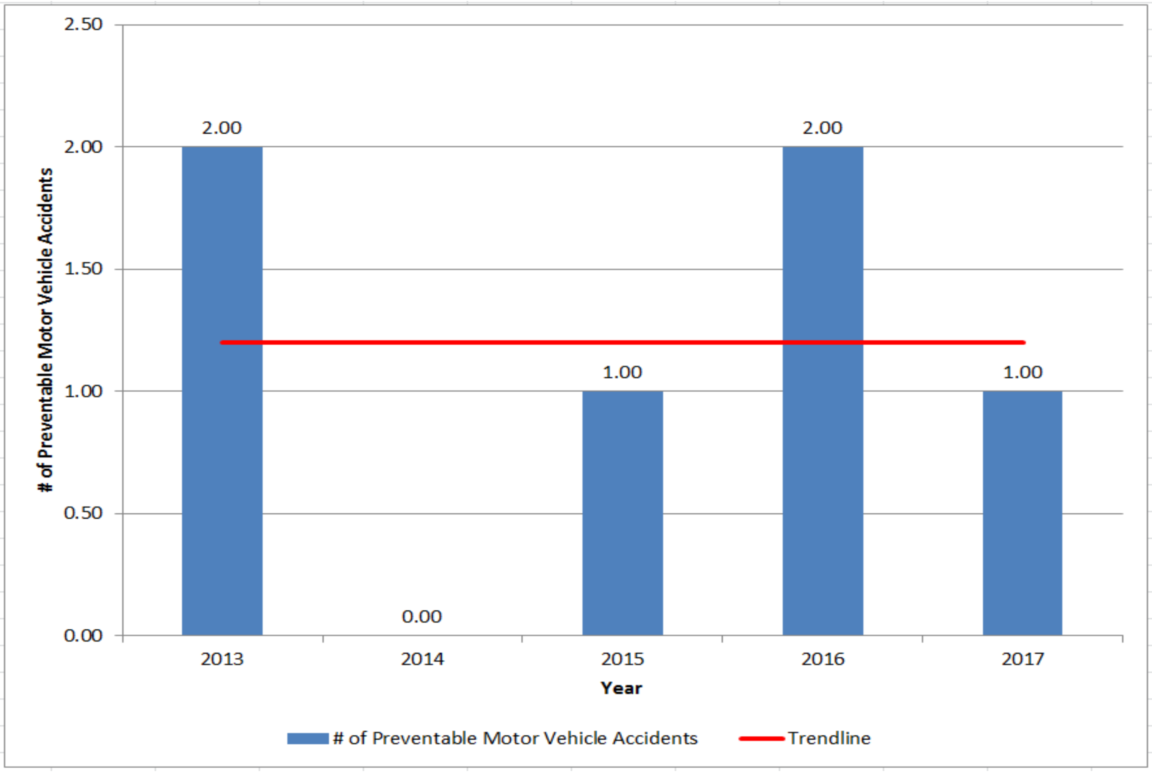


Figure 1 - Number of Preventable Motor Vehicle Accidents

HOSSM Targets to achieve one or less preventable motor vehicle accidents per year.

Completion of Safe Work Observations

HOSSM also focuses on continuing its program of Safe Work Observations ("SWOs"). SWOs are completed on staff performing their daily job tasks whether it is in the office or out in the field to ensure the safety of all staff by identifying potential hazards to be eliminated or controlled. The culture of safety that has been established at HOSSM is mimicked by the achieved results illustrated in Figure 2.

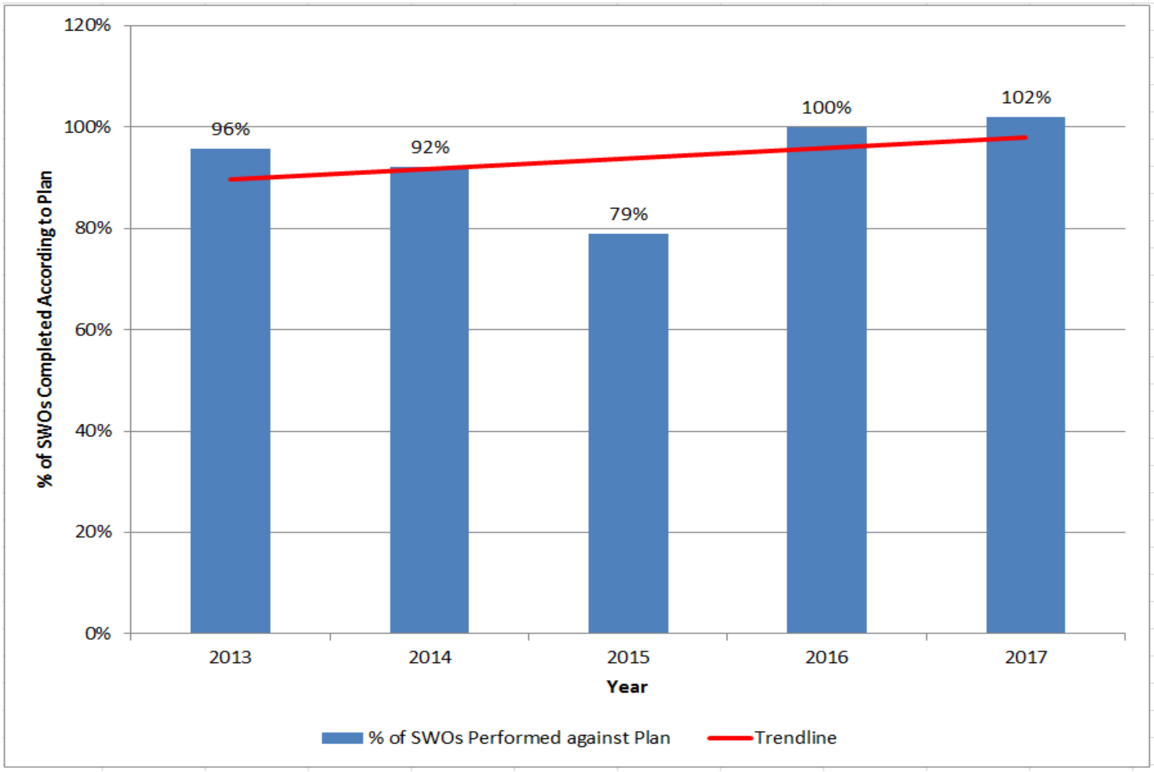


Figure 2 - Percent of Planned SWOs Performed According to Plan

1.4.2 CONTINUED VALUE CREATION

HOSSM continues to ensure they are managing the assets in a cost efficient manner that demonstrates value to customers. Other KPIs previously tracked for this corporate driver are now metrics found on the proposed Scorecard in Section 1.5 of this exhibit.

OM&A at Approved Levels

This KPI tracks that all planned work was accomplished within established OM&A budget. It is measured as the actual spent as a percent of budget. HOSSM's achieved results are found in Figure 3.

OM&A savings in 2017 resulted from employee attrition primarily in management and administration roles, combined with some productivity savings in operations and maintenance. A small portion of the work program (low risk work) was deferred into 2018 due to a shortage of resources for part of the year as the Company was not willing to take the risk of performing work at the detriment to health & safety.

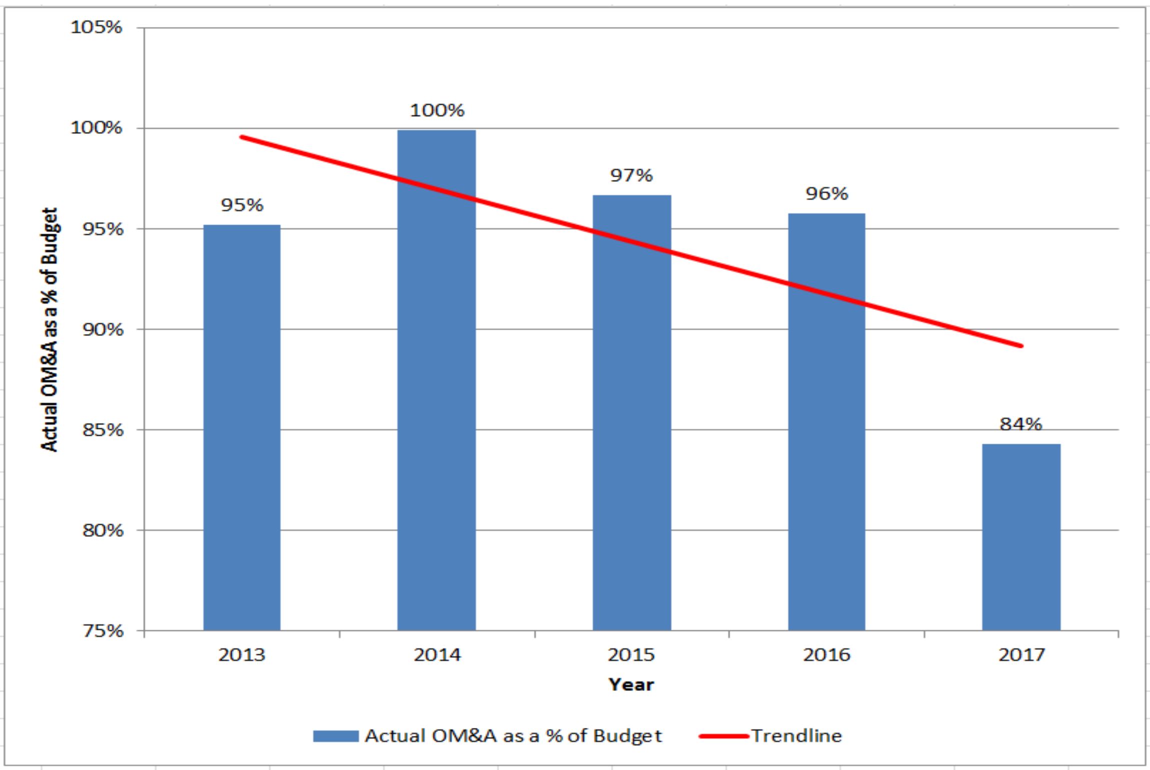


Figure 3 - Actual OM&A as a % of Budget

1.4.3 RISK MANAGEMENT

Self-Reports of Non-Compliance with NERC Standards

HOSSM strives to maintain compliance with reliability standards mandated by the North American Electric Reliability Corporation ("NERC") for an Electricity Transmitter. The tracking of this measure will also ensure the appropriate compliance program is in place.

In 2016, HOSSM started tracking any incidents that required HOSSM to file a self-report of non-compliance. The target has been set a zero high-risk regulatory compliance and operational incidents.

HOSSM had one self-reporting non-compliance incident in each of 2016 and 2017. On August 2016, HOSSM self-reported non-compliance with a two phase patch installation planned. A decision was made to not proceed with phase two of the security patching SCADA system due to integration and future decommissioning. Remedial actions have been implemented to reduce vulnerabilities to a manageable level.

In August 2017 HOSSM placed an asset in service without receiving a Registration of Approval Notice ("RAN") from the IESO. A process is now in place whereby project engineering will confirm with HOSSM system control that a RAN has been received prior to placing any new equipment into service.

Job Plan Quality Assurance Reviews

The completion and maintenance of documented Job Plans is required by the Electrical Utility Safety Rule 107. The Job Plan process is *"to establish a **safe work area**, by identifying the job steps, **hazards** and appropriate barriers."*[3]

Job Plans therefore are to mitigate safety risks by hazard identification for workers in the field. To ensure the Job Plan is completed accurately and demonstrates a comprehensive knowledge of the work environment, HOSSM implemented a Quality Assurance ("QA") program. HOSSM started tracking the completion of QA reviews against the number of those targeted at the end of 2013 to ensure the right program is in place.

[3] Hydro One Safety Rules 2014, Rule 107, Job Planning

The targeted number of reviews to be completed in a calendar year is determined in the first quarter of the year. The decrease in the number of QA reviews completed in 2016 is due to a number of staffing vacancies that occurred throughout the year resulting in a lower number of QA reviews completed. However, overall the trend is improving as demonstrated in Figure 4.

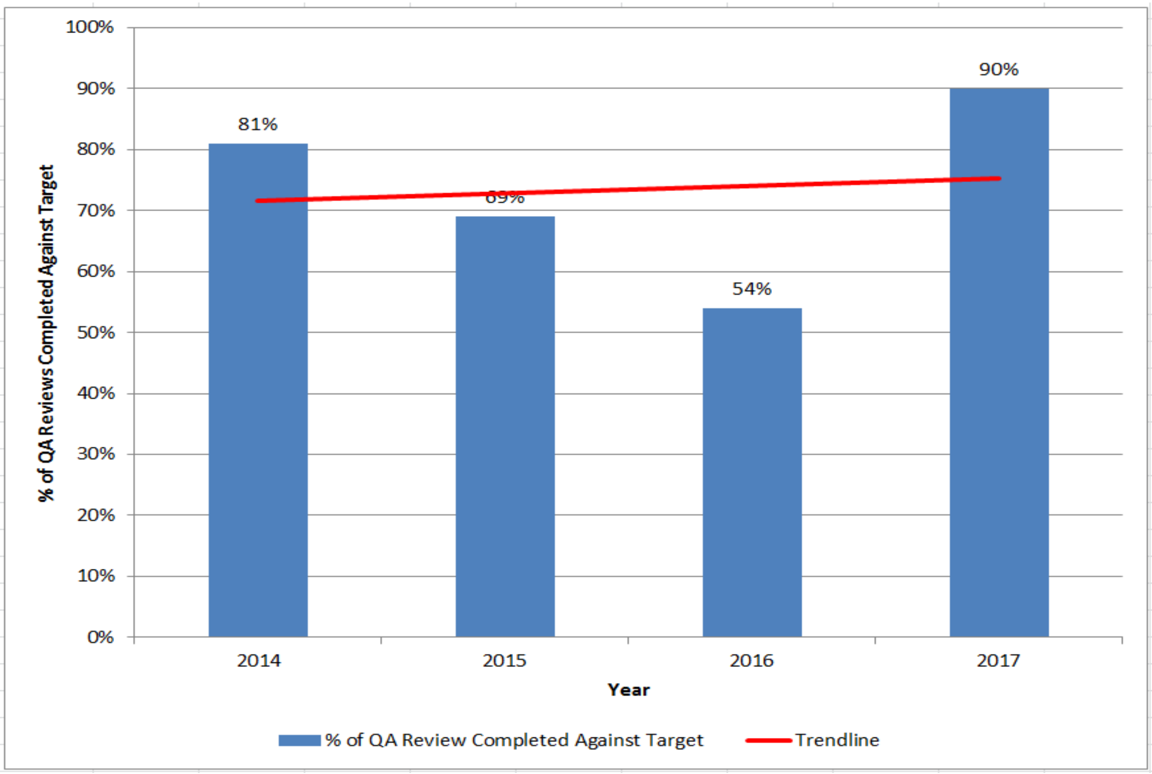


Figure 4 - QA Reviews Completed Against Target (in %)

1.4.4 INVESTMENT IN OUR PEOPLE

People development is important for HOSSM to promote individual development and provide appropriate tools and resources to enable managers to build effective teams. This helps to increase competence, efficiency, productivity and succession planning opportunities both at HOSSM and Hydro One, with the benefits ultimately received by the ratepayer. HOSSM used to track the number of management and leadership courses were completed by HOSSM Management staff. As HOSSM staff will be integrated into Hydro One, these metrics are no longer tracked. However, the HOSSM Management team has completed Hydro One's management course entitled the Craft of Management.

1.5 PROPOSED HYDRO ONE SAULT STE. MARIE SCORECARD

Figure 5, HOSSM's proposed scorecard, shows the performance metrics HOSSM expects to be measured against and the associated annual results, targets and trending of each metric. The descriptions of the various metrics can be found in section 1.6 of this exhibit.

Performance Outcomes	Performance Categories	Measures	Historical Years 2011	2012	2013	2014	2015	2016	2017	Trend	2023 Targets
Customer Focus **Services are provided in a manner that responds to identified customer preferences.**	**Service Quality**	Satisfaction with Outage Planning Procedures (% Satisfied)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	90%
		Customer Delivery Point Performance Standard Outliers as % of Total Delivery Points	33%	24%	25%	20%	16%	0%	0%	▲	11.80%
	Customer Satisfaction	Overall % Customer Satisfaction in Corporate Survey	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	85%
Operational Effectiveness **Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.**	**Safety**	Recordable Incidents (# of injuries/illnesses per 200,000 hours worked)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	<1.0
	System Reliability	T-SAIFI (Average # Power Interruptions per Delivery Point)	2.14	2.24	1.16	0.32	1.11	0.37	0.42	▲	0.53
		T-SAIDI (Average # Minutes of Power Interruptions per Delivery Point)	296.71	176.76	233.7	9.3	85.8	10.0	30.9	▲	42.1
		System Unavailability (%) - Lines	N/A	N/A	0.25	0.02	0.09	0.39	0.10	▲	0.38
		System Unavailability (%) - Stations	N/A	N/A	0.03	0.00	0.13	0.00	0.00	-	0.38
		Unsupplied Energy (minutes)	N/A	N/A	12.63	2.98	16.42	2.88	9.19	▲	11.4
	Asset Management	In-Service Additions (% of HOSSM's Capital Plan)	120%	111%	99%	99%	92%	98%	108.5 %	-	100%
		CapEx as % of Budget	97%	113%	95%	95%	100%	101%	129%	▲	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	10.69 %	6.87%	4.38%	4.33%	5.76 %	5.81 %	6.23%	▲	7.80%
		Sustainment Capital per Gross Fixed Asset Value (%)	7.55%	4.03%	1.29%	1.25%	2.70 %	2.70 %	3.69%	▲	4.40%
		OM&A per Gross Fixed Asset Value (%)	3.15%	2.84%	3.09%	3.08%	3.06 %	3.10 %	2.54%	▲	1.80%

Public Policy Responsiveness **Transmitters deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).**	**Connection of Renewable Generation**	% on time completion of renewables connection impact assessments		100%	100%	100%	100%	100%	100%	100%	-	100%
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met		N/A	N/A	N/A	100%	100%	100%	100%	-	100%
Financial Performance **Financial viability is maintained; and savings from operational effectiveness are sustainable.**	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.21	1.34	1.69	1.67	1.62	1.33	1.38	N/A	N/A
		Leverage: Total Debt (includes short-term & long-term debt) to Equity Ratio		1.13	1.10	1.09	1.12	1.04	1.03	0.97	N/A	N/A
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.42%	8.93%	9.36%	9.30 %	9.19 %	N/A	N/A	N/A
			Achieved	10.94 %	11.86 %	11.51 %	11.42 %	9.66 %	9.93 %	N/A	N/A	N/A

Legend:

▲ Performance Improving
▼ Performance deteriorating
- No change

Figure 5 - Proposed Hydro One Sault Ste. Marie Scorecard

1.6 OVERVIEW OF HOSSM'S SCORECARD METRIC PERFORMANCE

The following sections include a description of each metric on the proposed scorecard. For each metric, there is a current description and a description of how the metric will evolve as HOSSM adopts Hydro One's methodologies and continues to migrate its records and data into Hydro One's systems through the integration process. Annual targets for 2023 have been proposed for each metric that coincides with the five years included in the Transmission System Plan ("TSP") and is aligned with Hydro One's 2023 transmission scorecard targets.

1.6.1 CUSTOMER FOCUS

The Customer Focus measures found in

Table **2** were selected to demonstrate that the *"services are provided in a manner that responds to identified customer preferences"* as stated in the RRF[4].

Table 2 - Customer Focus Measures

Performance Category	Measures
Service Quality	Satisfaction with Outage Planning Procedures (% Satisfied)
	Customer Delivery Point Performance, Standard outliers as % of Total Delivery Points
Customer Satisfaction	Overall Customer Satisfaction, corporate survey (% Satisfied)

[4] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, page 2.

Service Quality: Satisfaction with Outage Planning Procedures (per cent satisfied)

Description

In the past, HOSSM traditionally monitored and measured customer satisfaction with outage planning procedures through feedback received through day to day communication with customers and during customer engagement meetings.

Once the outage planning for HOSSM's transmission system has been fully integrated with Hydro One's practices, HOSSM's customer satisfaction with outage planning procedures will be measured using a transactional survey which asks respondents to rate Outage Planning procedures on a five-point scale. The question posed will be: How would you rate Hydro One's Ontario Grid Control Centre procedures on outage planning?

Performance

HOSSM does not formally track customer satisfaction with outage planning procedures but believes customer satisfaction related to outage planning procedures has been maintained at a medium to high level.

Service Quality: Customer Delivery Point Performance, Standard Outliers as per cent of Total Delivery Points

Description

HOSSM measures this metric as the percentage of customer Delivery Points ("DPs") deemed as either group or individual outliers. HOSSM's Customer Delivery Point Performance Standards ("CDPPS") can be found as Exhibit C, Tab 2, Schedule 1, Attachment 1.

On integration with Hydro One, HOSSM will continue to measure this metric as the percentage of group or individual outliers compared to the total number of delivery points on the transmission system but will adopt Hydro One's CDPPS.

Performance

Figure 6 below illustrates the continuous improvement in HOSSM's Customer Delivery Point Performance ("CDPP") over the last five years. This has been accomplished through targeting specific areas with reliability concerns for capital replacement and upgrade projects. Examples include the 2015 capital projects to upgrade Highway 101 TS and Anjigami TS to mitigate reliability issues through the installation of improved fault isolation, fault sensing equipment and improved protection coordination. Included in the 2018 to 2026 Business Plan is the upgrade and conductor replacement of the 115kV circuit Sault #3 Line that runs from Third Line TS to MacKay TS. Sault Line #3 and is currently de-rated by HOSSM and registered with the IESO due to multiple sleeve failures and aging conductor.

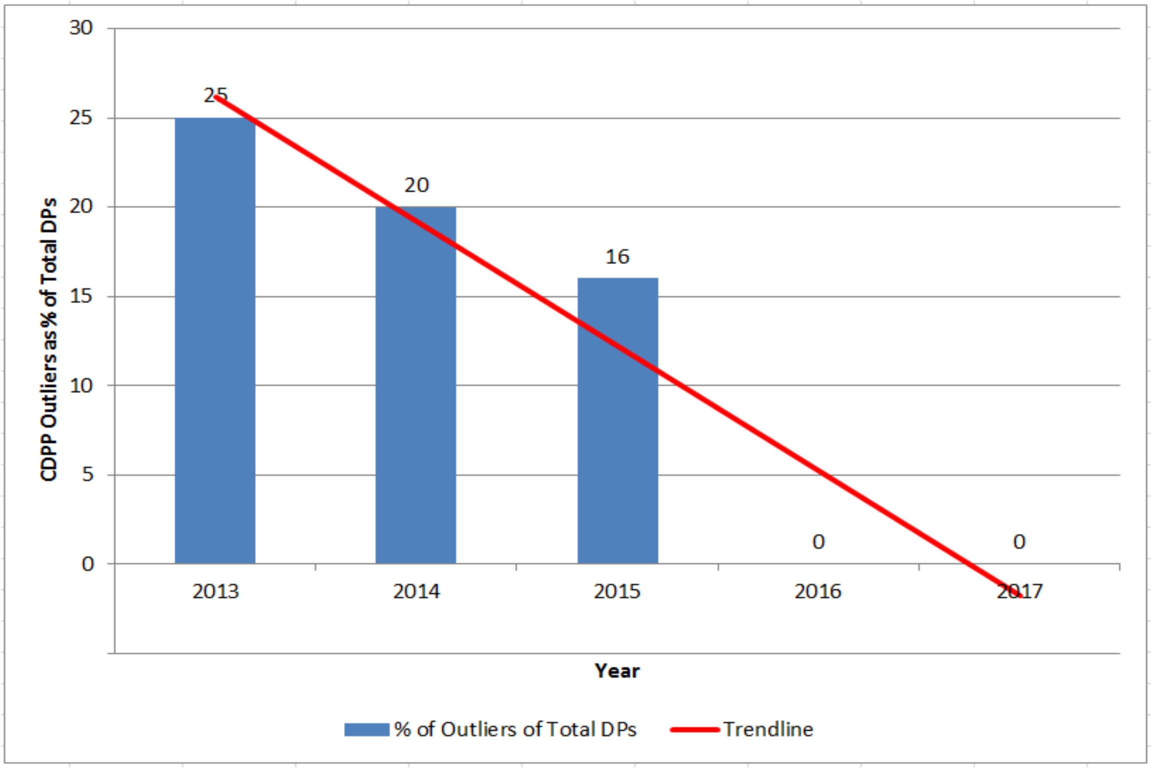


Figure 6 - Customer Delivery Point Performance

Customer Satisfaction: Overall Customer Satisfaction in Corporate Survey (% satisfied)

Description

In the past, HOSSM has traditionally managed overall customer satisfaction through its customer engagement activities with all directly connected customers (Local Distribution Companies, Large Industrial customers and Generation customers). In customer meetings, HOSSM facilitated open discussions regarding customer adequacy and power quality requirements, operational impacts and future system planning and maintenance initiatives.

In proceeding EB-2016-0356, HOSSM stated for the Overall Customer Satisfaction metric that in “2017, HOSSM intends to develop and implement a process to measure and produce quantitative customer satisfaction results for purposes of tracking this metric."[5] As HOSSM integrates with Hydro One, HOSSM customers will be included in Hydro One's customer satisfaction surveys online, followed by computer-assisted telephone interviews based on customer preference or availability. Overall customer satisfaction will be measured by surveying the overall satisfaction level of its three major transmission customer segments: 1) Transmission End Users; 2) LDCs; and 3) Transmission-connected Customer Generators. The survey will also measure key areas that affect satisfaction among large Transmission customers by monitoring performance in four key service areas: 1) Price; 2) Customer Service; 3) Product Quality and Reliability; and 4) Relationship. The survey will measure opinions and perceptions of customers on how well the company is meeting their expectations.

Performance

Customer Engagement sessions have been positively received by HOSSM customers. The minutes for the 2018 Customer Engagement meetings are found as Exhibit B2, Tab 2, Schedule 1, attachments 1 to 4. Customers have been positive regarding overall customer satisfaction related to any transmission services.

[5] EB-2016-0356, Response to interrogatory 3-Satff-4.

1.6.2 OPERATIONAL EFFECTIVENESS

The measures in Table 3 demonstrate HOSSM's commitment to continuous improvement in performance and execution. The measures also show that HOSSM delivers on system reliability and service quality objectives.

Table 3 - Operational Effectiveness Measures

Performance Category	Measure
Safety	Recordable Rate (#Recordable Injuries/Illnesses per 200,000 hours worked)
System Reliability	T-SAIFI (Average # of times that power to a Customer is interrupted per Delivery Point)
	T-SAIDI (Average # minutes that power to a Customer is interrupted per Delivery Point)
	System Unavailability (% of time system equipment is unavailable)
	Unsupplied Energy (minutes)
Asset & Project Management	In-Service Additions (% of Capital Plan)
	Capital Expenditures as % of Budget
Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)
	Sustainment Capital/Gross Fixed Asset Value (%)
	OM&A per Gross Fixed Asset Value (%)

Safety: Recordable Incident Rate (# of Recordable Injuries/Illnesses per 200,000 Hours Worked)

Description

This is a new metric that has been added to HOSSM's scorecard. It tracks the number of work-related injuries or illnesses per 200,000 hours worked (recordable rate), that result in: 1) restricted work; 2) medical attention beyond first aid; 3) death or; 4) any other significant work-related injury or illness diagnosed by a physician or other healthcare professional and is confirmed by a Hydro One Occupational Health Nurse. This measure only applies to employees of the company and excludes contractors and the general public.

Performance

Although this is a new metric to the scorecard, HOSSM has been tracking lost time injuries and illnesses as a KPI. HOSSM has had no lost injuries or work-related illnesses in the last five years. HOSSM will do the upmost to continue to ensure the health and safety of staff is maintained over the next five years.

System Reliability: T-SAIFI, T-SAIDI, System Unavailability and Unsupplied Energy

HOSSM tracks and measures the reliability of its electricity transmission system using distinct measures, defined as:

1. Transmission System Average Interruption Frequency Index ("T-SAIFI");
2. Transmission System Average Interruption Duration Index ("T-SAIDI");
3. System Unavailability; and
4. Unsupplied Energy.

Descriptions

Transmission System Average Interruption Frequency Index

T-SAIFI is the average frequency of delivery point interruptions and is used as an indicator of the average number of unplanned interruptions that customers experienced per delivery point in the year. Both momentary (less than 1 minute in duration) and sustained interruptions (equal to 1 minute or more in duration) are currently included in this metric.

As the integration with Hydro One progresses, this metric will be divided into momentary ("T-SAIFI-M") and sustained outages ("T-SAIFI-S") to align with Hydro One's tracking of these metrics.

Transmission System Average Interruption Duration Index

T-SAIDI is the average duration of sustained delivery point interruptions – those interruptions greater than one minute in duration – and is used as an indicator of the average minutes of unplanned interruptions that customers experience per delivery point in the year. Only sustained (1 minute and longer) interruptions contribute to this measure.

Based on the uncertainty in the performance on this measure year-over-year, the future targets are set based on multiple year averages.

System Unavailability

System unavailability examines the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. This measure does not consider the subordinate outages of healthy transmission equipment removed from service as a result of an outage caused by other equipment.

This was not a metric that HOSSM has specifically tracked in the past. Information collected in the Control Room Log at HOSSM has been reviewed and gathered to provide historical results for this metric.

Unsupplied Energy

Unsupplied Energy is the total energy not supplied to customers during the year, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to make the performance comparable to that of other utilities. The unit of the measure of normalized unsupplied energy is expressed in “system minutes”.

Performance

HOSSM's performance for these reliability metrics are discussed further in Exhibit C, Tab 2, Schedule 1.

Asset Management: In-Service Additions as a Percent of the Capital Plan

Description

This metric is a measurement of the percent of budgeted capital work completed on or ahead of schedule and placed in-service compared to the HOSSM's plan. The metric is consistent with regulatory requirements of the Transmission Business, measuring the % of Capital In-Serviced relative to plan.

Performance

HOSSM's performance has been relatively stable in recent years as demonstrated in Figure 7.

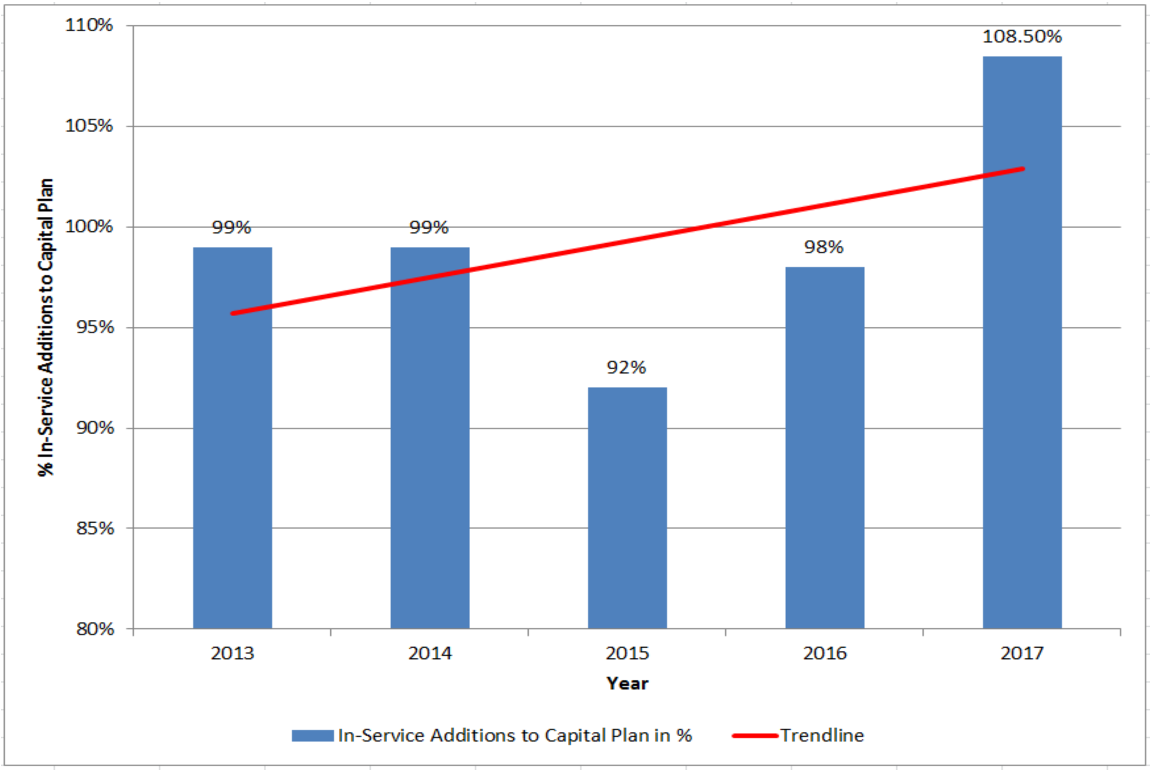


Figure 7 - In-Service Additions as a % of the Capital Plan

Asset & Project Management: Capital Expenditures as per cent of Budget

Description

HOSSM measures the progress of its capital expenditures towards the approved plan as the ratio of actual total capital expenditures to the total amount of planed capital expenditures. This is the same methodology that Hydro One uses to measure success for this scorecard metric.

Performance

The annual results for this metric have been relatively stable over the historical years and HOSSM expects to continue to work within the budget. The annual results are shown in Figure 8. In 2017 a $3.3 million that was not budgeted for was made to Batchewana First

Nation for land rights. This payment is discussed further in Exhibit E, Tab 1, Schedule 2. If this payment was not made, the CapEx as a percentage of the budget would have been 94%.

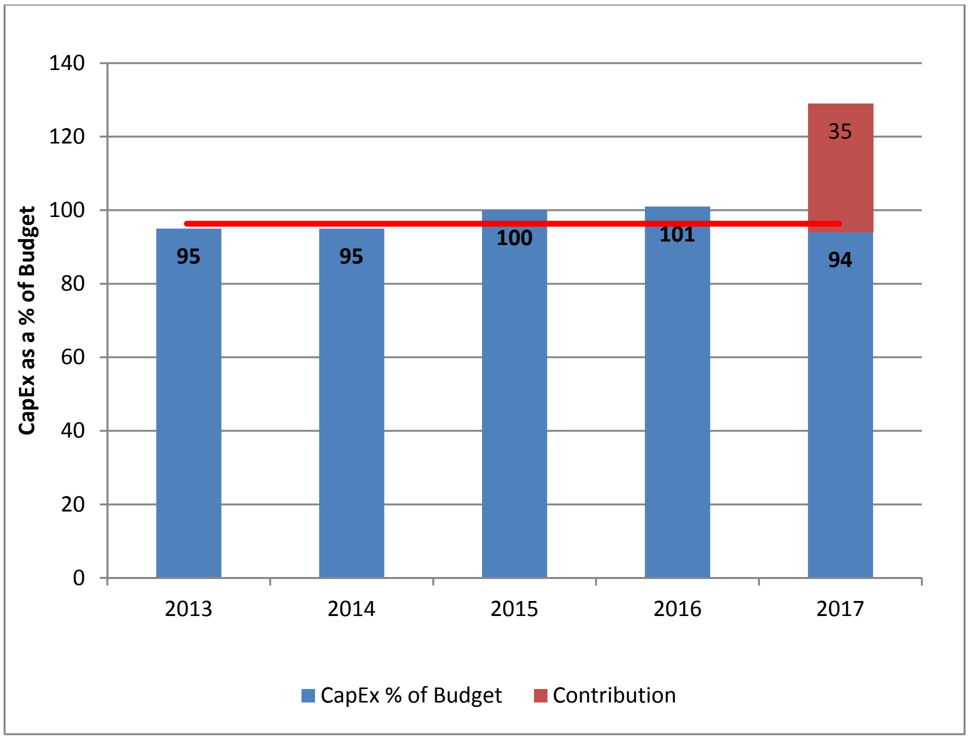


Figure 8 - Capital Expenditures as % of Budget

Cost Control

HOSSM has selected the following cost control metrics to be included in the proposed scorecard:

- Total OM&A and Capital Expenditures ("CapEx") as a percentage of Gross Fixed Asset ("GFA") Value;
- Sustainment Capital as a percentage of Gross Fixed Asset Value; and
- OM&A as a percentage of Gross Fixed Asset Value.

Taken together, these three metrics provide a view of HOSSM's ability to efficiently leverage its capital and OM&A budgets to support its asset base and to improve efficiency over time.

Total OM&A and Capital Expenditures ("CapEx") as a percentage of Gross Fixed Asset ("GFA") Value

Description

This metric was chosen to demonstrate the cost effectiveness by comparing the ratio of Total Capital and OM&A to the Gross Fixed Asset Value.

Performance

The annual results for this metric are illustrated in Figure 9. Due to a decision to spend minimal Capital in each of 2013 and 2014, performance in these two years is low. Starting in 2015 more Capital has been spent to maintain the assets as required to improve reliability.

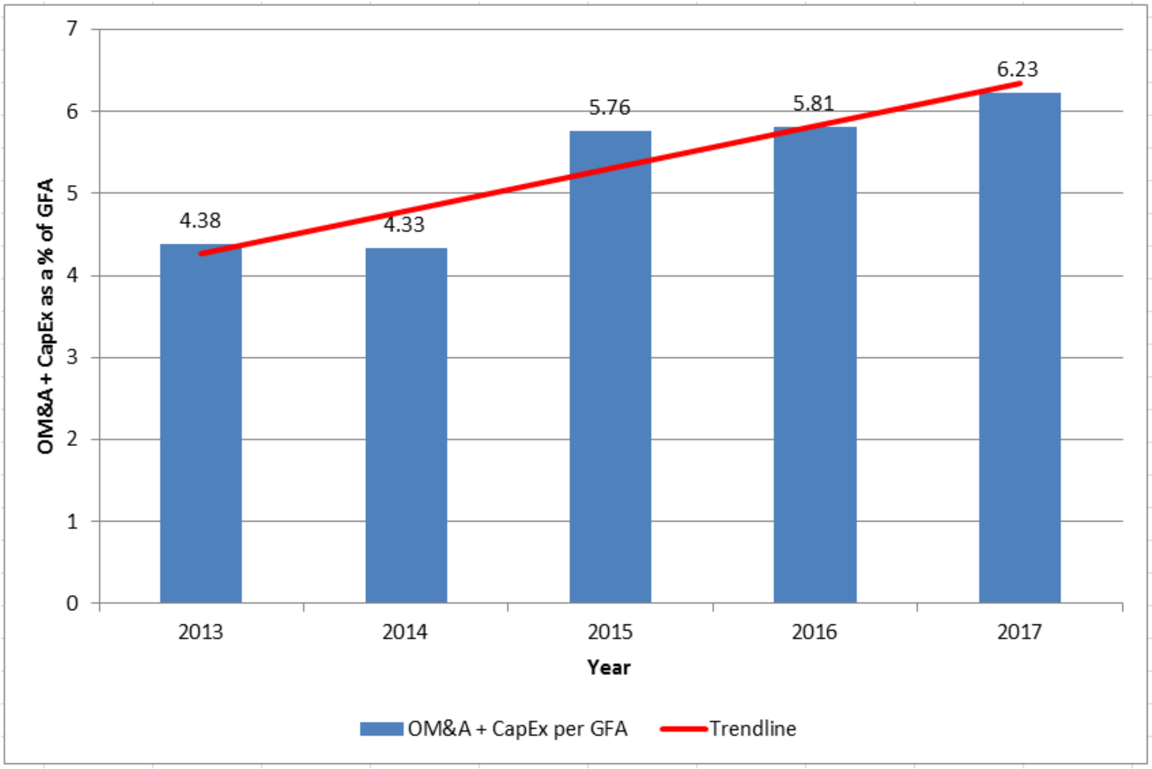


Figure 9 - Total OM&A and Capital Expenditures ("CapEx") as a percentage of Gross Fixed Asset ("GFA") Value

Sustainment Capital as a percentage of Gross Fixed Asset Value

Description

This metric demonstrates cost effectiveness by comparing the ratio of Sustainment Capital to Gross Fixed Asset Value.

Performance

The annual results for the Sustainment Capital as a percentage of Gross Fixed Asset Value are shown in Figure 10. Minimal Capital was spent in 2013 and 2014 as a result of a management decision. In subsequent years, additional funding was spent to maintain the integrity of the system and assets.

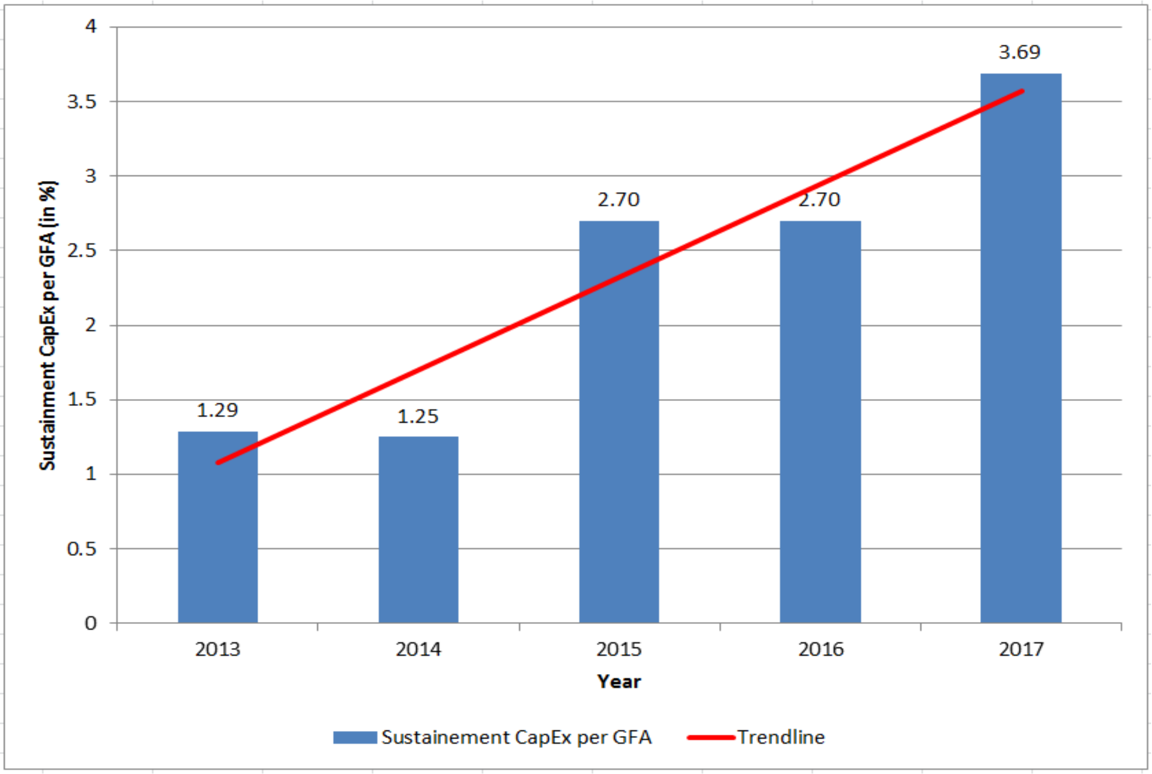


Figure 10 - Sustainment CapEx per GFA (%)

OM&A as a percentage of Gross Fixed Asset Value

Description

This metric demonstrates cost effectiveness by comparing the ratio of OM&A expenditures to Gross Fixed Asset Value.

Performance

Figure 11 illustrates the annual results for OM&A as a percentage of the GFA. HOSSM's performance is improving in this area due to investments that targeted assets in poorer health that required additional maintenance.

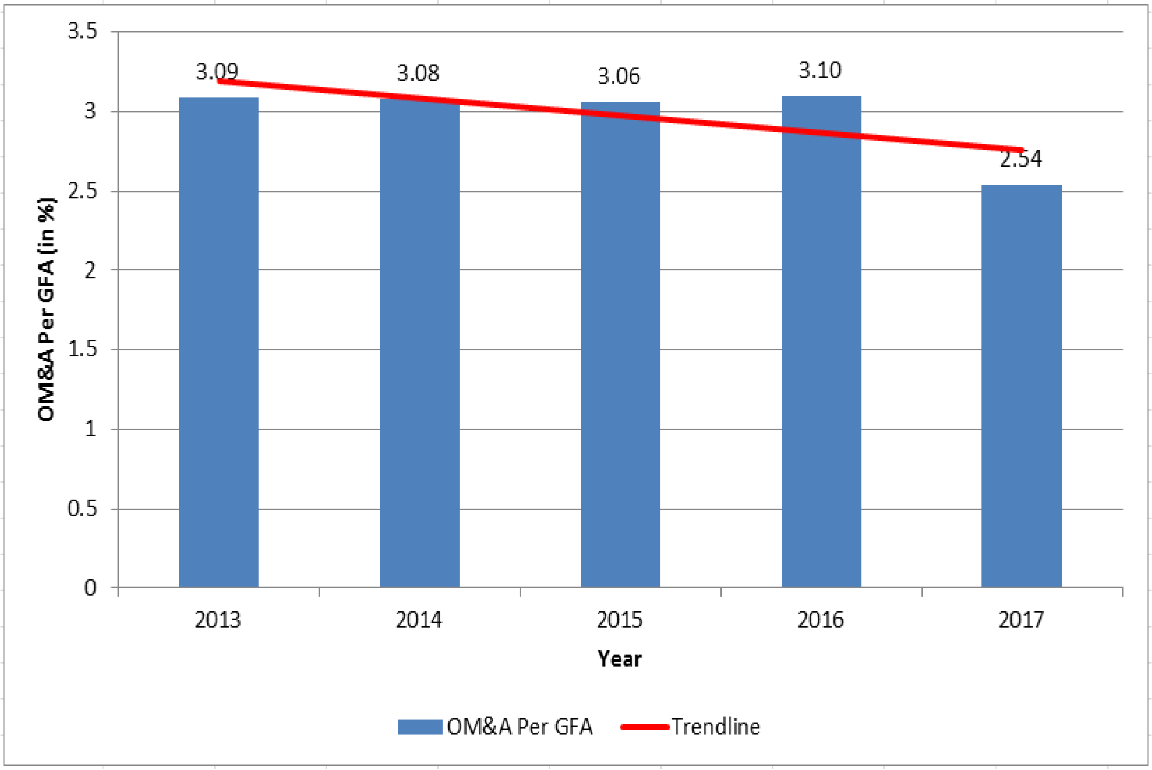


Figure 11 - OM&A Per Gross Fixed Asset

1.6.3 PUBLIC POLICY RESPONSIVENESS

The measures in Table 4 were selected to demonstrate Hydro One's commitment to deliver on the obligations mandated by the government and regulatory agencies.

Table 4- Public Policy Responsiveness Measures

Performance Category	Measure
Renewable Energy	% on-time completion of renewables connection impact assessments
Regional Infrastructure Planning (RIP)	Regional Infrastructure Planning Progress - % Deliverables met

Renewable Energy: On-Time Completion of Renewables Customer Impact Assessments (“CIAs”) (as per cent of CIAs completed on time)

Description

For transmission-connected generators, HOSSM completes customer impact assessments, and measures its performance in the successful completion of these assessments against a period of 150 days.

Performance

HOSSM has completed 100% of the required customer impact assessments within 150 days for all of the historical years of this application.

Regional Infrastructure: Regional Infrastructure Planning Progress (per cent of Deliverables Met)

Description

To drive performance relative to the Public Policy Responsiveness outcome, HOSSM measures the performance of its Regional Infrastructure Planning process. The Regional Infrastructure Planning process was established by the OEB in the third quarter of 2013. The company measures the percentage of deliverables completed within the prescribed timelines in the Transmission System Code, which includes certain deliverables such as plans, Regional Planning reports, and LDC Planning Status letters for their rate applications.

Performance

HOSSM has completed 100% of its Regional Infrastructure Planning Process commitments since 2013 and fully expects this to continue.

1.6.4 FINANCIAL PERFORMANCE

The measures in Table 5 were selected to provide financial visibility and to demonstrate that the continuous improvements in execution and cost performance highlighted in ‘Operational Effectiveness’ are sustainable.

Table 5- Financial Performance Measures

Performance Category	Measures
Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)
	Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio
	Profitability: Regulatory Return on Equity -Deemed Return on Equity (included in rates)
	Profitability: Regulatory Return on Equity -Achieved Regulated Return on Equity

Liquidity: Current Ratio (Current Assets/Current Liabilities)

Description

The company measures the ratio of current assets to current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year and that can be used to fund daily operations and pay ongoing expenses. Current liabilities are defined as short term debts or financial obligations that become due within the year.

Performance

HOSSM’s performance regarding the Current Ratio metric has been fairly stable over the historical years as illustrated in Figure 12. The 2017 result indicates that for every one dollar of current liabilities, Hydro One had $1.38 in current assets. Current assets are defined as cash or cash equivalents to be converted to cash within the year and which can be used to fund daily operations and pay ongoing expenses. Current liabilities are defined as debt or other financial obligations that become due within the year.

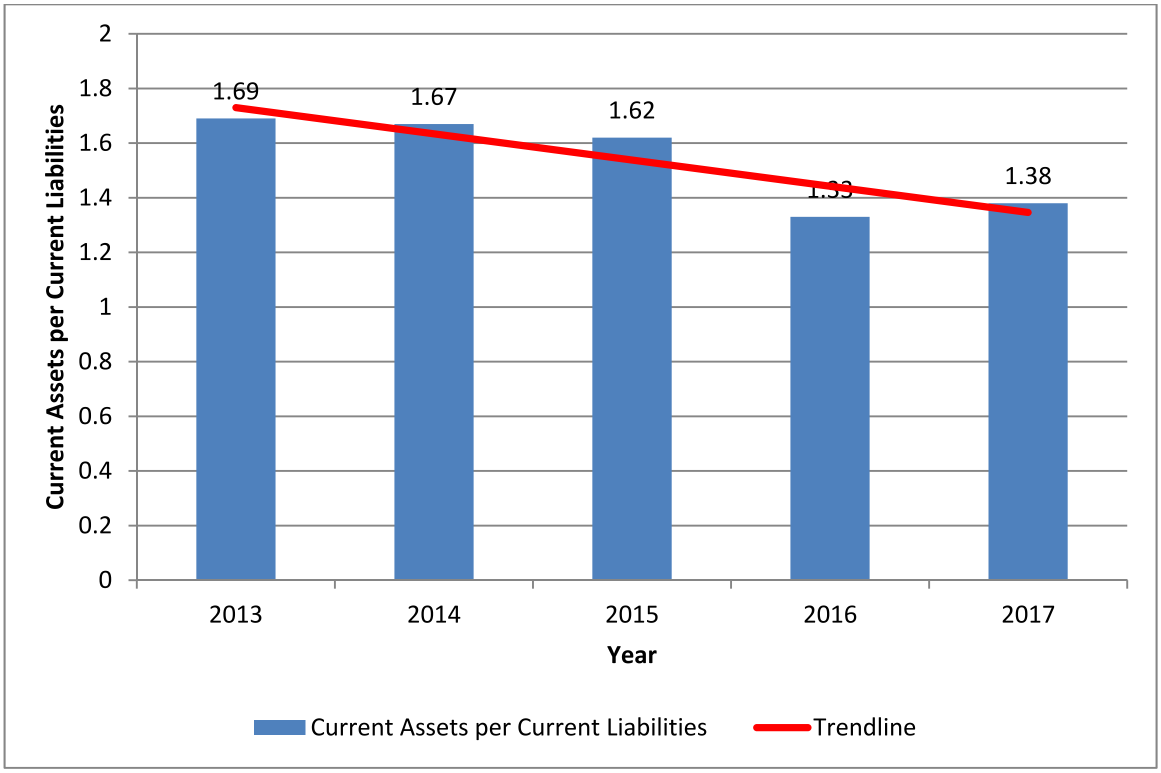


Figure 12 - Current Ratio

Leverage: Total Debt to Equity Ratio

Description

The debt-to-equity ratio is a measure of the company's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60 per cent to 40 per cent debt-to-equity structure (a ratio of 1.5). This metric includes short-term and long-term debt.

Performance

HOSSM's annual Leverage: Total Debt to Equity Ratio is shown in Figure 13. HOSSM's average debt to equity ratio over the past five years was 1.05, and is trending downwards below the OEB-deemed ratio of 1.50. The ratio is trending downward primarily due to principal payments on long term debt trending from approximately $2 M to $2.5 M in annual principal repayments over the last 4 years.

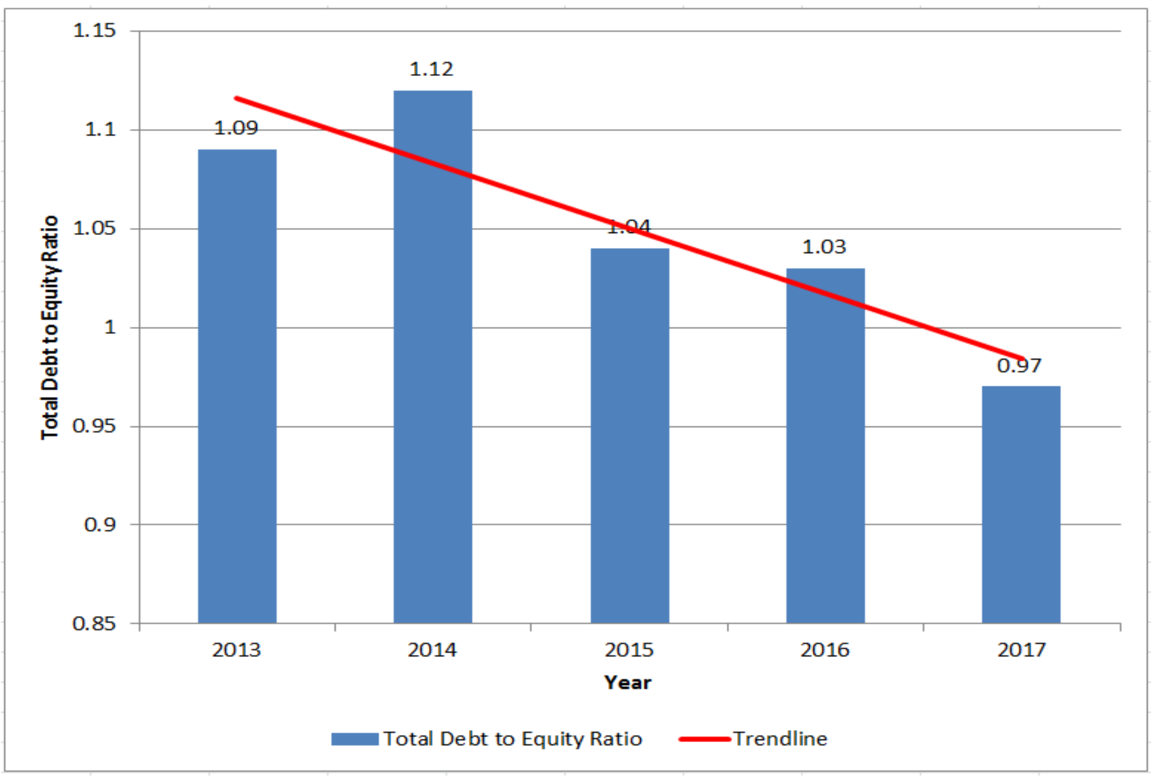


Figure 13 - Leverage: Total Debt to Equity Ratio

Profitability: Regulatory Return on Equity -Achieved Regulated Return on Equity

Description

This metric measures HOSSM's achieved regulated Return on Equity earned in the preceding fiscal year. The reported return is calculated on the same basis that was used in establishing the base rates. This shows the utility's actual Return on Equity earned each year.

Performance

HOSSM's 2017 achieved regulatory return on equity was 9.21 per cent against the OEB-deemed return on equity of 8.78 per cent. HOSSM's average achieved regulatory return on equity over the past five years was 10.42 per cent. This is shown in Figure 14.

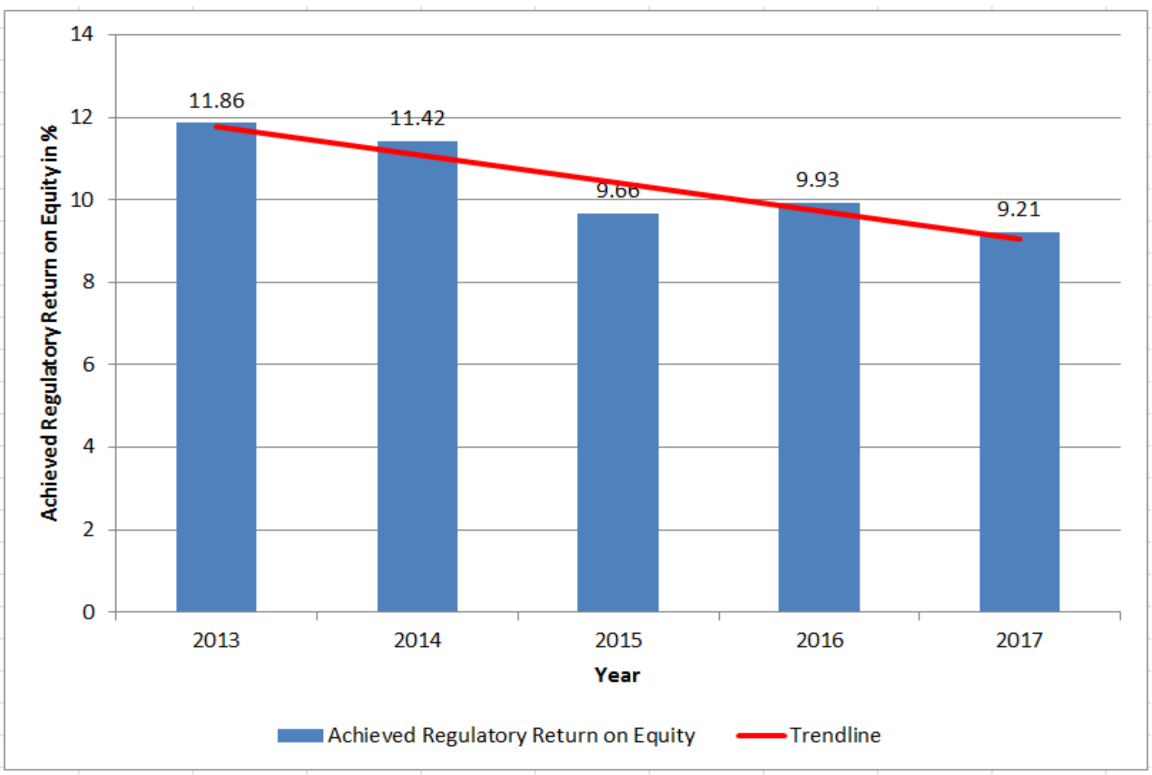


Figure 14 - Achieved Regulatory Return on Equity

1.7 SUMMARY

HOSSM's scorecard includes implemented measures that reflect the overall business and are expected to positively influence intended performance outcomes. As the integration between HOSSM and Hydro One progresses, HOSSM will adopt Hydro One's scorecard metrics and methodologies. In the meantime HOSSM will continue to develop processes and mechanisms to track the required information to align its scorecard to that of Hydro One.

HOSSM will continue to develop and implement KPIs to track its performance as it adopts Hydro One's processes and practices. This will facilitate a smoother transition into one company, monitor continuous improvement, demonstrate value to existing customers and maintain the level of service expected by its customers.

RELIABILITY PERFORMANCE

1. INTRODUCTION

Hydro One Sault Ste. Marie ("HOSSM") strives to provide and maintain the high level of reliability that customers have come to expect. To ensure success, HOSSM:

- continually monitors the transmission system;
- investigates the causes of power interruptions to customers;
- documents and tracks power quality and reliability performance;
- proactively identifies trends that indicate the possible requirement for remedial action;
- implements capital investments to mitigate risks to reliability; and
- sets targets for the reliability metrics that have been included on the proposed transmission scorecard.

Some of the metrics HOSSM uses to track and measure success include:

- Customer Delivery Point Performance Standards ("CDPPS");
- System Average Interruption Frequency Index ("SAIFI");
- System Average Interruption Duration Index ("SAIDI");
- Unsupplied Energy ("UE"); and
- System Unavailability for Transmission Lines and Stations.

These metrics are discussed in the following sections.

1.1 CUSTOMER DELIVERY POINT PERFORMANCE STANDARD

In accordance with the Ontario Energy Board ("OEB") Transmission System Code requirement 4.5, HOSSM has developed Customer Delivery Point Performance Standards ("CDPPS"), which relate the reliability of supply to the size of load being served at the Delivery Point ("DP"). The standard includes measures for both frequency and duration of interruption. HOSSM's CDPPS are defined in four load categories: 0-15 MW (i.e. local distribution delivery points); 15-40 MW (i.e. Sault Area Hospital); 40-80 MW (i.e. local city circuits); and >80 MW (i.e. Essar Algoma Steel). HOSSM's CDPPS is found as Attachment 1 to this exhibit.

The CDPP Standards approved in OEB proceeding RP-1999-0057/EB-2002-0424, consist of two components;

- Group CDPP Standards that relate the reliability of supply to the size of load being served at the delivery point; and
- Individual CDPP Standards that maintain a customer's individual historical delivery point performance.

The standard generally considers two concepts for identifying concerns; these are the "outlier" concept and the "inlier" concept.

Performance triggers to identify deteriorating reliability have been established based on the size of load being served. For this purpose, the load is the delivery point's total average station gross load[1] as measured in megawatts. DP performance "outliers" status

[1] Total Average Station Gross Load (MW) = (Total Energy Delivered to the Station (MWh) + Total Energy Generated at the Station Site (MWh)) / 8760 hours.

is defined when the three year rolling average of delivery point performance falls below the minimum standard of performance for frequency and/or duration of interruptions.
The Standard Average and Minimum Standard of performance relates to the reliability of supply to the size of load being served at the delivery point measures for both frequency (total interruptions / load block) and duration (total minutes / load block) of interruption. The standard was established utilizing Hydro One Networks Inc.'s historical (1991-2000) statistics, shown in Table 1. For the purpose of the illustrations below the standard was calculated by using the Hydro One standards and multiplying by the number of delivery points in the respective load category.

Table 1 - Delivery Point Performance Standards[2]

Performance Measures	Delivery Point Performance Standards (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		**>15 to 40MW**		**>40 to 80MW**		**>80MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

The standard also includes an "inlier" concept, which is a provision to establish a performance standard to maintain the historical reliability performance levels at each customer delivery point and avoid deteriorating trends, notwithstanding the fact that they may have satisfactory performance. Baseline triggers were set using ten years of the customers' individual historical delivery point performance data. Delivery point performance that is worse than either baseline trigger for frequency or duration in two consecutive years is a candidate for remedial action. In this case, HOSSM will initiate

[2] GLPT CDPPS, page 3, Table 1, dated December 2007. See Attachment #1 to this exhibit.

technical and financial evaluations in cooperation with the impacted customers to determine the root cause of the unreliability and to identify remedial options to consider for implementation.

Relevant CDPP statistics are reviewed with each customer on an annual basis at a Customer Engagement Meeting to discuss details of past service interruption, to provide an opportunity to discuss any potential remedial actions and to ensure HOSSM is aware of the customer satisfaction level. For further discussion on Customer Engagement Meetings see Exhibit B2, Tab 3, Schedule 1.

Table 2 shows HOSSM's CDPP Minimum Standards and Standard Averages for each load category. This is calculated as the number of DPs in each of HOSSM's respective load category multiplied by each of the CDPP Standards for DP Frequency of Interruptions (Outages) and DP Interruption Duration (Minutes) found in table 1.

Table 2 - HOSSM CDPP Standards

Customer Deliver Point Load Categories	Number of Delivery Points	Standards	Interruption Frequency (Outages)	Interruption Duration (Minutes)
>80 MW	1	Minimum Standard	1.0	25
		Standard Average	0.3	5
40-80 MW	1	Minimum Standard	1.5	55
		Standard Average	0.5	11
15-40 MW	2	Minimum Standard	2	280
		Standard Average	2.2	44
0-15 MW	14	Minimum Standard	126	5,040
		Standard Average	57.4	1,246

Figure 1 shows HOSSM's annual interruption frequency for each load block category for 2013 to 2017. As illustrated on the graph, there were no outages in this five year period for the >80 MW load block category.

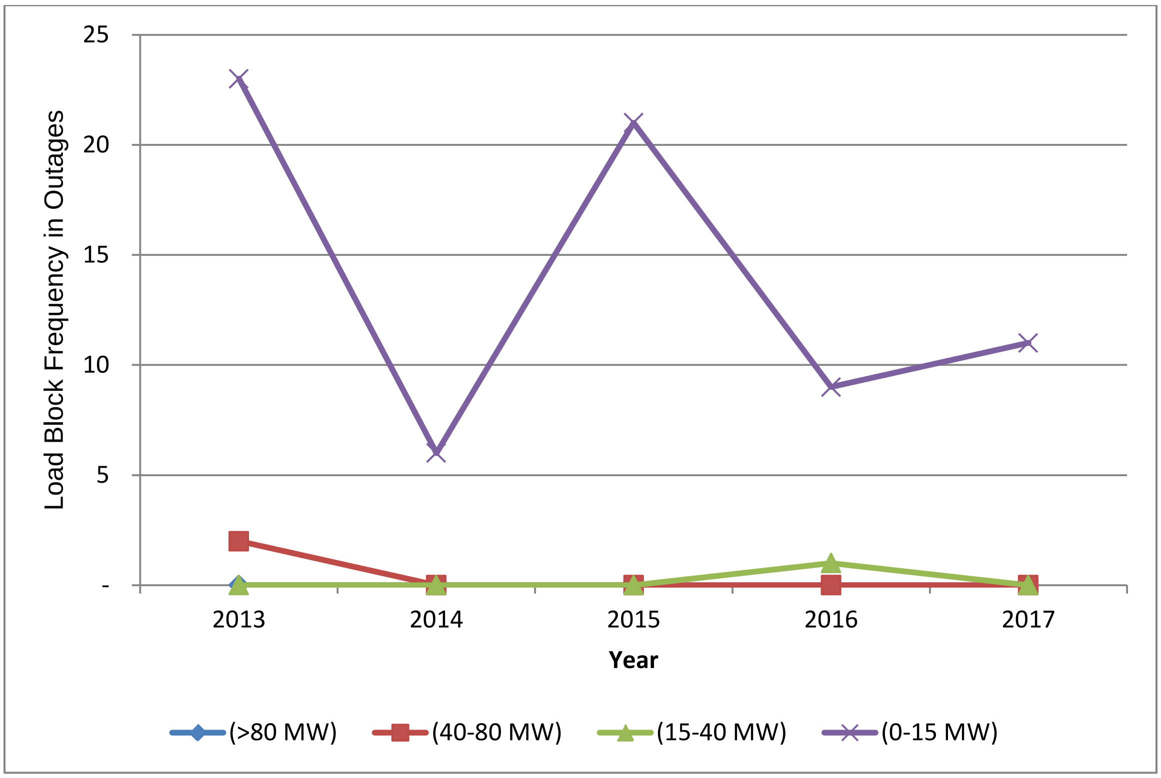


Figure 1 - Annual CDPPS Interruption Load Category Frequency in Outages

Figure 2 illustrates HOSSM's annual interruption duration for each load block category for 2013 to 2017. As previously stated, there were no load interruptions from 2013 to 2017 for the >80 MW load block category.

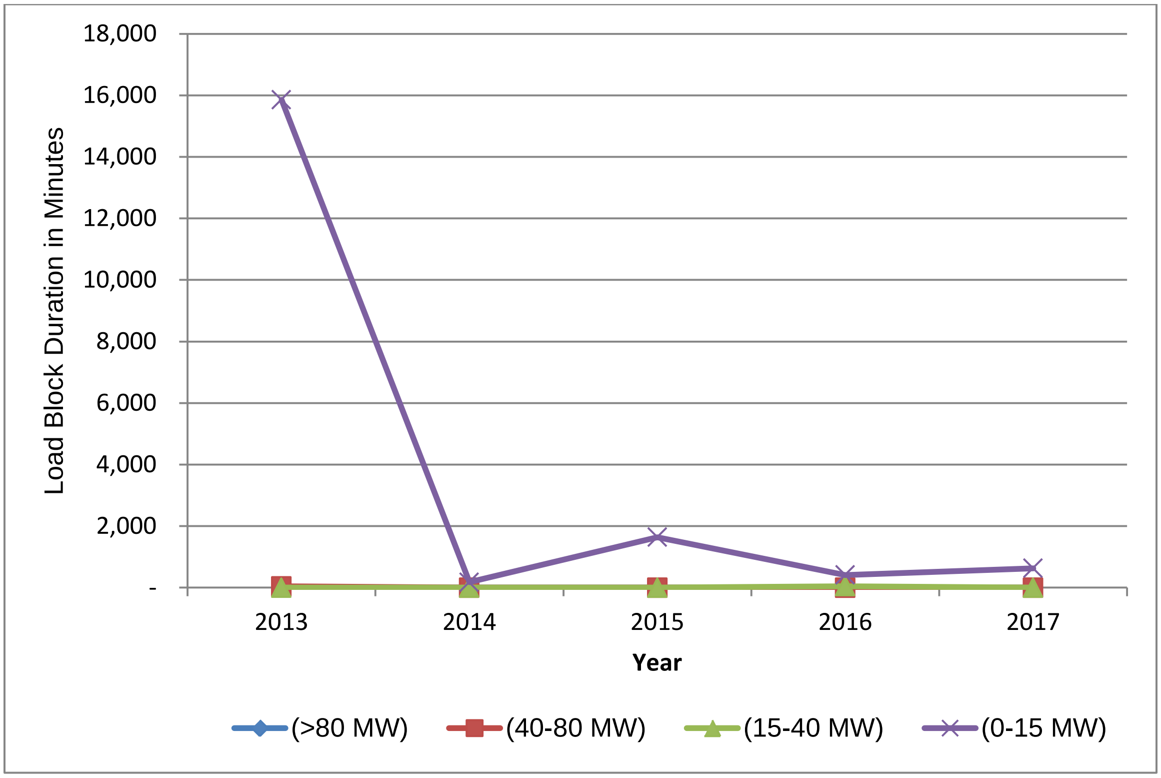


Figure 2- Annual CDPP Load Category Interruption Duration in Minutes

1.1.1 LOAD BLOCK CATEGORIES PERFORMANCE

As illustrated by the CDPPS, HOSSM has performed extremely well in the upper 3 load categories; >80MW, 40-80MW, 15-40MW. Although the overall reliability of the 0-15MW load category performance is acceptable when compared to the standards, there are customer delivery points that require improvements to reduce interruption durations.

>80 MW and 40-80 MW Load Categories

No significant issues currently impact reliability at these delivery point load categories. Regularly scheduled asset maintenance and sustainment capital investments maintain the appropriate level of reliability required by the standards.

15-40 MW Load Category

In 2016, at Third Line TS, there was a 47 minute interruption that resulted from the misoperation of an under voltage relay. Since the relay was electromechanical, staff was dispatched to investigate the relay operation. The investigation confirmed there had been no under voltage condition. This relay was determined to be faulty and was replaced.

0-15 MW Load Category

In 2015, duration of interruptions increased slightly in the 0-15 MW load category from the previous year primarily as a result of an equipment failure on the No. 3 Sault 115kV line. The No. 3 Sault circuit is the main connection element for two HOSSM stations which supply local distribution. HOSSM repaired a section of line to resolve the issue at the time to return service quality to a level expected by the connected customers. Test results indicate the conductor is in an end of life condition. Engineering for the replacement of this circuit is currently scheduled in the Business Plan to start in 2018. For further information regarding this capital project refer to Exhibit B1, Tab 1, Schedule 1, Chapter 4, ISD #SR-02.

Additionally in the 0-15 MW load category HOSSM continues to experience outages related supply points in the Wawa area. Although HOSSM has experienced a positive trend in performance, HOSSM will continue with plans to improve reliability in the area.

1.2 SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX AND SYSTEM AVERAGE INTERRUPTION DURATION INDEX

HOSSM also uses CDPP statistics to report Canadian Electricity Association's System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). SAIFI is measured in number of power interruptions experienced by customers in a calendar year. SAIDI is the duration of interruptions measured in minutes per calendar year. T-SAIDI performance can vary significantly from year to year due to following reasons:

- limited number of DPs;
- small number of events which can contribute most of the index;
- major events which occurred and will happen randomly; and
- radially supplied DP performance, which can vary significantly due to lack of alternative source.

In order to compare the HOSSM stats with the CEA All Canada Composite, the following CEA criterion has been applied:

- Planned interruptions are excluded;
- Customer caused interruptions are excluded;
- Low voltage equipment caused interruptions are excluded; and
- Momentary interruptions are excluded.

HOSSM currently utilizes these industry standards for internal benchmarking and to identify local system reliability trends year over year and determine if the asset management strategies and objectives are improving overall system reliability.

Figure 3 compares HOSSM's annual SAIFI for sustained interruptions to the Canadian Electricity Association ("CEA") composite annual SAIFI. Sustained interruptions are those interruptions lasting one minute or more. The established CEA composite performance indicator is the aggregate performance of CEA participating transmission utilities from across Canada, some of which are government-owned.

Please note that the CEA statistics were not available for 2017 at the time of the development of this exhibit.

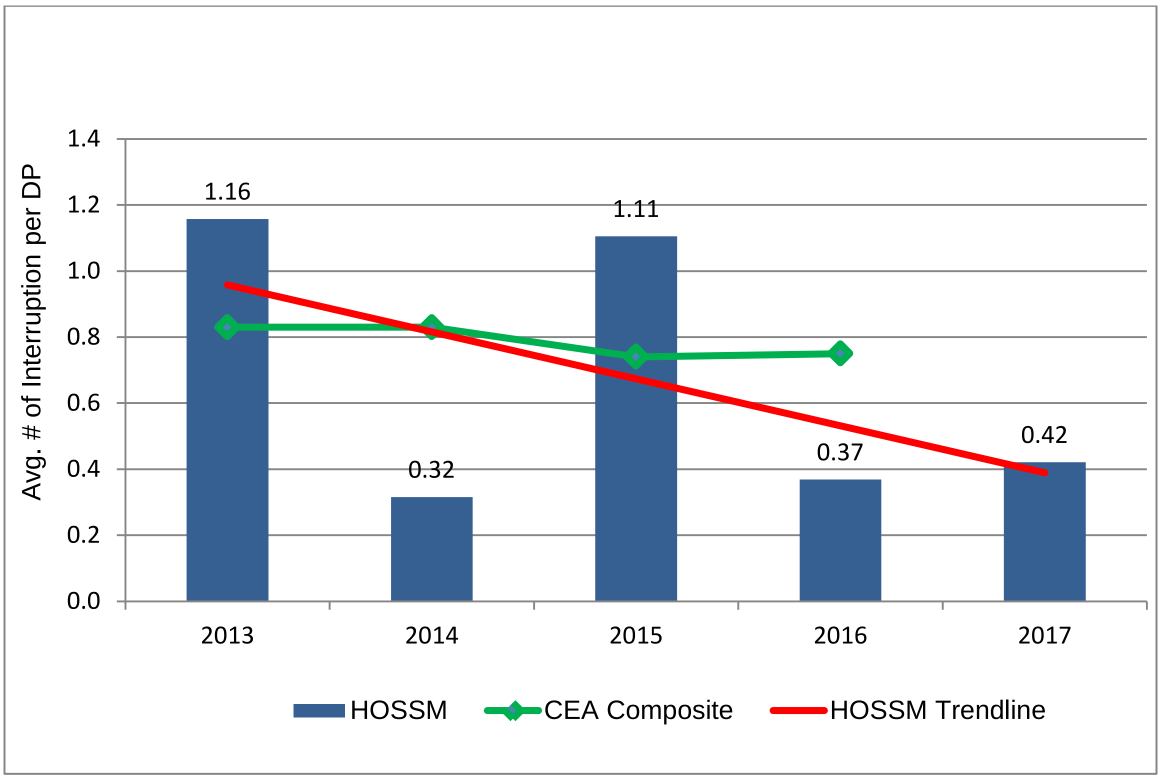


Figure 3 - Comparison of Hydro One Sault Ste. Marie Frequency of Sustained Interruptions to CEA Composite

Figure 4 compares HOSSM's annual SAIDI to the Canadian Electricity Association ("CEA") composite annual SAIDI.

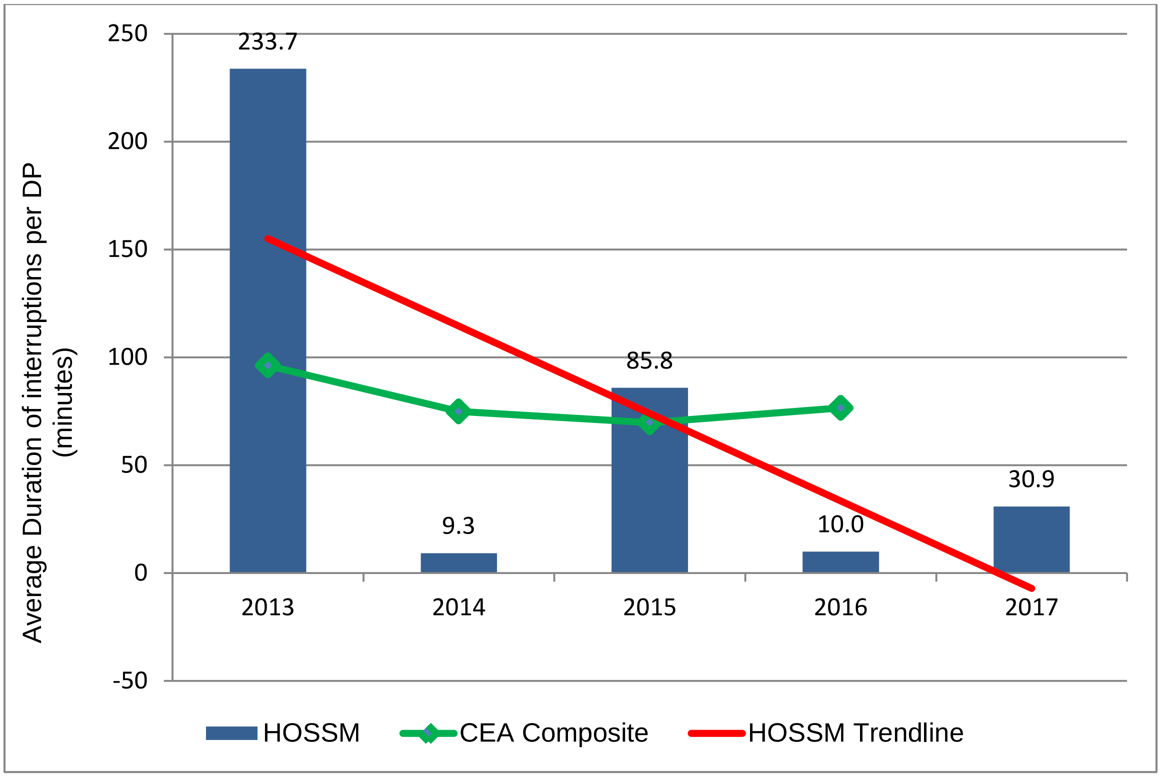


Figure 4 - Comparison of Hydro One Sault Ste. Marie's Duration of Interruptions to CEA Composite

1.2.1 SAIFI AND SAIDI TRENDS

The HOSSM SAIFI statistics indicate that the system average is improving over the last five years and is being maintained below one outage over the last 4 years.

The HOSSM SAIDI statistics indicate that the system average is improving and is being maintained below 100 minutes over the last 4 years. These trends indicate overall improvement in frequency and duration of customer interruptions. The major contributor to high 2013 T-SAIDI number was a 115 kV Andrews Line outage caused by ice build-up on the line. The total interruption duration attributed to Andrew TS is 53.8 minutes T-SAIDI.

1.3 UNSUPPLIED ENERGY

One industry standard indicator of power system unreliability is called Unsupplied Energy ("UE"). Unsupplied Energy is the total energy not supplied to customers during the year, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to make the performance comparable to that of other utilities. The unit of the measure of normalized unsupplied energy is expressed in "system minutes".

Figure 5 illustrates HOSSM's unsupplied energy performance as compared to the CEA composite performance. The additional rigour applied as Hydro One's investment planning processes is adopted as part of integration process progresses will ensure specific areas will continue to be targeted for investment to improve reliability. It is therefore expected that HOSSM will continue to perform well in this area.

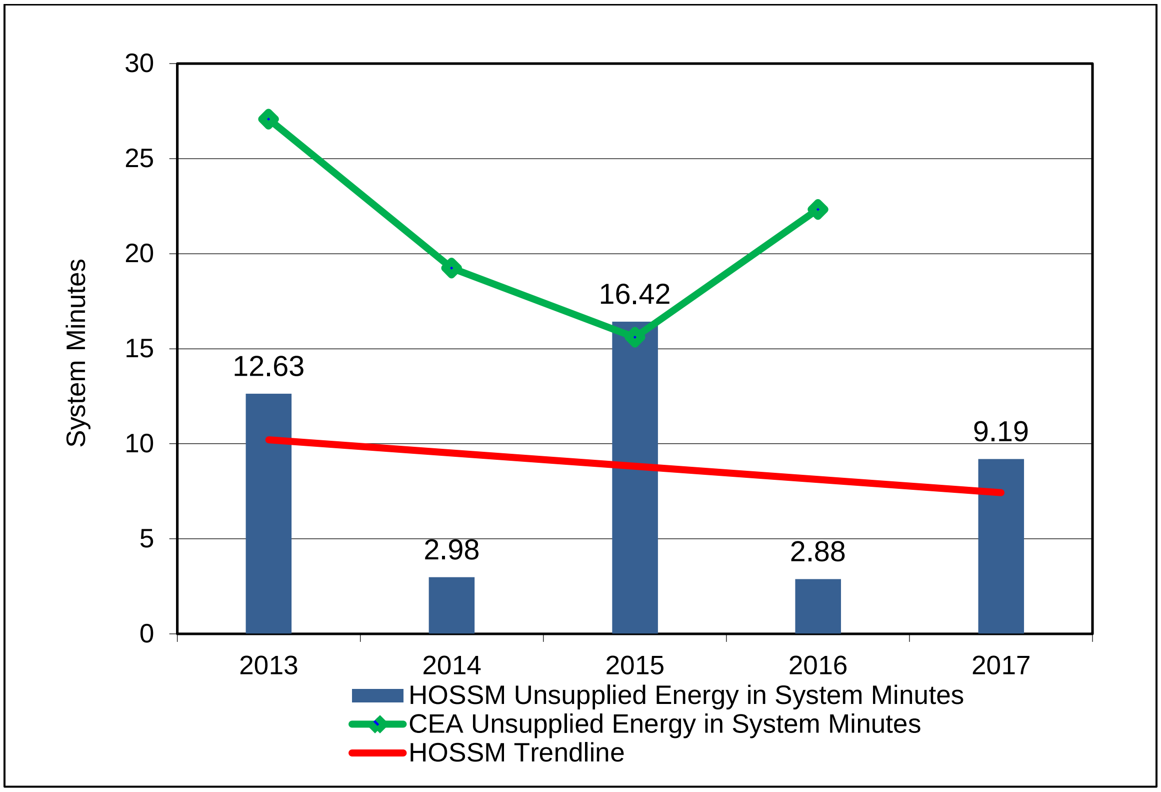


Figure 5 – HOSSM Unsupplied Energy in System Minutes

1.3.1 UNSUPPLIED ENERGY TREND

The IESO has developed a process and defined specific criteria for the assessment of the HOSSM local area performance. Through this process and based on the assessment results of performance, HOSSM is assigned a category reflecting its overall level of performance. HOSSM is in good standing with respect to this performance measure. Two events contributed most of the 2015 Unsupplied Energy:

- A lightning strike damaged a fused disconnect switch at Hollingsworth TS, that resulted in 2 DP interruptions with a total of 1758 MW*minutes unsupplied energy; and

- Sault #3 115 kV Line caused 3 DP interruptions with a total of 1842 MW*minutes unsupplied energy.

These two events therefore contributed (1842 MW*minutes +1758 MW*minutes)/350.7 = 10.3 System Minutes to the Unsupplied Energy metric.

1.4 SYSTEM UNAVAILABILITY

Transmission System Unavailability measure captures the total duration that transmission equipment is not available for use within the system due to forced outages. It is sub-categorized as (1) Transmission Line Unavailability, and (2) Station Equipment Unavailability, based on the different characteristics of the equipment. Station equipment includes power transformers and circuit breakers, etc. The information derived from monitoring this measure is trended over time and helps influence business decisions that affect the reliability of transmission equipment. This measure is specifically defined to enable comparison with all-Canada averages from all transmission utilities which participate in the Equipment Reliability Information System program of the Transmission Consultative Committee on Outage Statistics at the Canadian Electricity Association.

Figure 6 illustrates HOSSM's Transmission Line Unavailability performance due to forced outages compared to the CEA composite group performance.

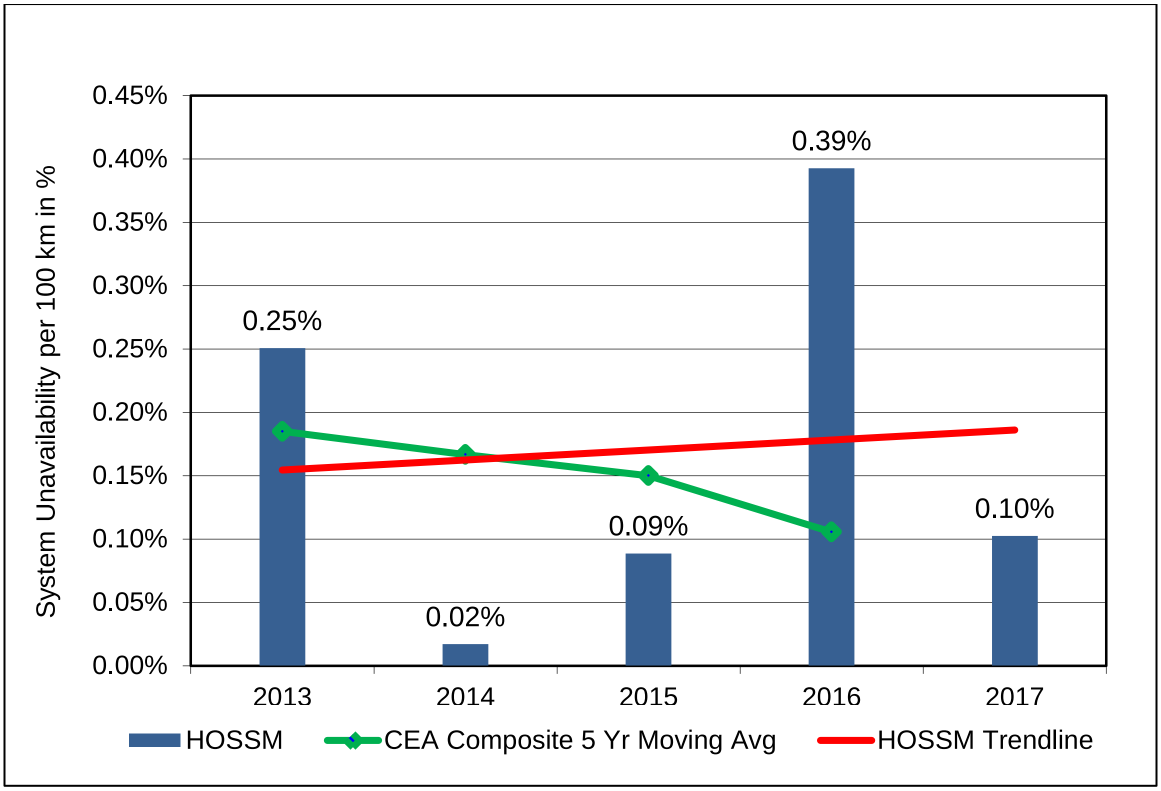


Figure 6 - Transmission Lines Unavailability per 100 km in % Compared to the CEA Composite

Figure 7 shows HOSSM’s Transmission Station Unavailability performance compared to the CEA composite group performance.

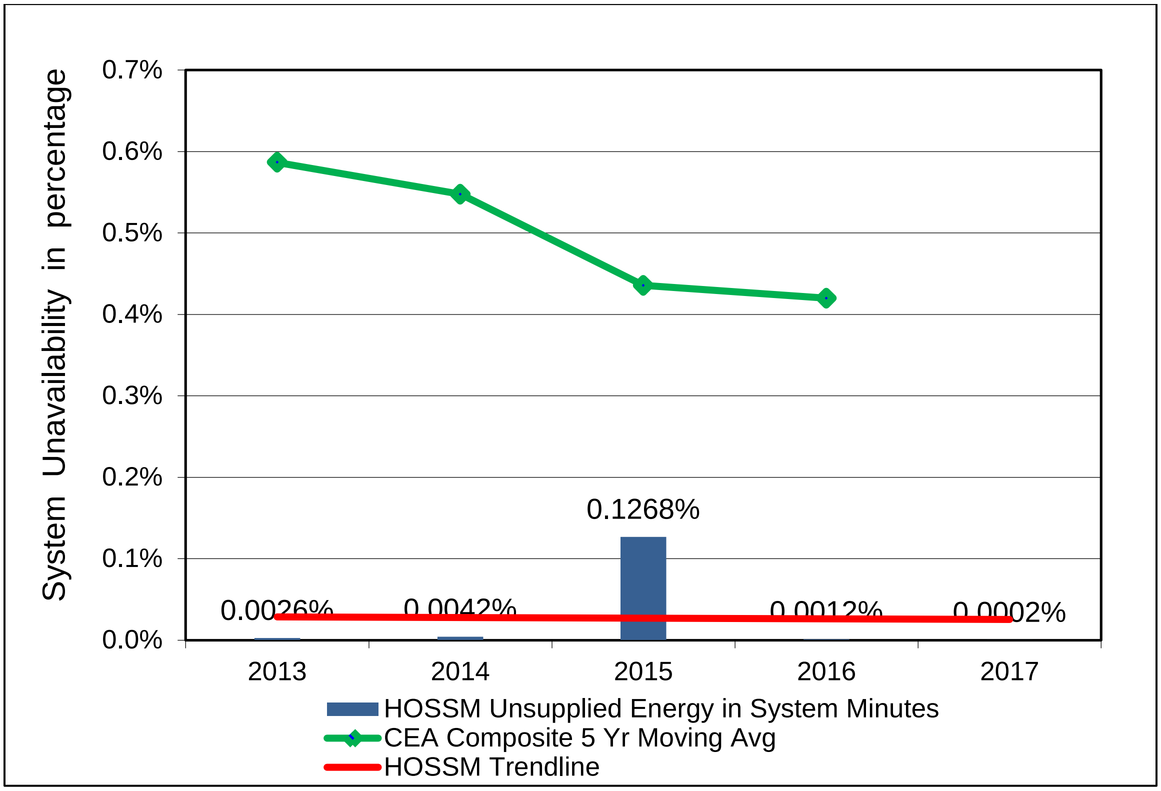


Figure 7 - HOSSM's Transmission Stations Unavailability Compared to the CEA Composite

1.4.1 SYSTEM UNAVAILABILITY TRENDS

Sault #3 Line is the cause of HOSSM's poorer performance for the transmission lines unavailability per 100 km metric. This circuit has been targeted for reconductoring and structure replacement during this Plan period. See Exhibit B1, Tab 1, Schedule 1, Chapter 4, ISD #SR-02 for further details.

HOSSM consistently performs better than the CEA composite group for the Transmission Station Unavailability metric. HOSSM fully expects this positive performance to continue.

Great Lakes Power

Great Lakes Power Limited – Transmission

Customer Delivery Point Performance Standards (CDPPS)

December 2007

1. Introduction

A transmitter shall develop performance standards that apply at the customer delivery point level and that: (Code section 4.5)

(a) reflect typical transmission system configurations that take into account the historical development of the transmitter's transmission system at the customer delivery point level;

(b) reflect historical performance at the customer delivery point level;

(c) are, where applicable, consistent with the comparable performance standards applicable to all delivery points throughout the transmitter's transmission system;

(d) establish acceptable bands of performance at the customer delivery point level for transmission system configurations, geographic area, load, and capacity levels;

(e) establish appropriate triggering events to be used to initiate technical and economic evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;

(f) establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken; and

(g) establish any circumstances in which the performance standards will not apply.

GLPL CDPP Standards will include two components:

1) Relate the reliability of supply to the size of load being served at the delivery point where the triggers are taken from Hydro One Networks Inc. (Hydro One) CDPPS document using Hydro One's statistics (refer to section 2) to identify GLPL Delivery Point (DP) performance "outliers".

2) Once data is available, maintain a customer's individual historical delivery point performance based on a minimum of five years of DP data to establish baseline triggers to identify GLPL DP performance "inliers".

The performance standards and triggers for identifying "outliers" are provided in section 3 and for identifying "inliers" are provided in section 4.

GLPL shall report to the Ontario Energy Board (the "Board") no later than the end of the first quarter of 2010 on the results of its assessment of its minimum performance standards and on whether it intends to propose any material changes for review and approval by the Board.[1]

2. Performance Standards Based on Size of Load Being Served

GLPL will use Hydro One's Customer Delivery Point Performance Standards and triggers based on the size of load being served (as measured in megawatts by a delivery point's total average station load[2]) are provided in Table 1 below.

Table 1: Delivery Point Performance Standards Based on Load Size

Performance Measures	**Delivery Point Performance Standards** (Based on a Delivery Point's Total Average Station Load)							
	0 to 15MW		**>15 to 40MW**		**>40 to 80MW**		**>80MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

The above Hydro One DP performance standards are based on historical (1991-2000) performance, as measured by the frequency and duration of outages of all momentary and sustained interruptions[3] caused by forced outages, excluding outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical performance. Included in this category of excluded events are the 1998 Ice Storm, 2003 Blackout, tornadoes, earthquakes, other acts of God and any other significant event having "excessive" impact on performance that is beyond the reasonable control of, and not a result of the fault or negligence of Hydro One.

[1] Board Decision and Order EB-2006-0201 dated June 6, 2007 section 4 page 8

[2] The load size groups are to be based on the total station gross load, where Average Gross Load (MW) = (Total Energy Delivered in the Station (MWh) + Total Energy Generated at the Station Site (MWh))/8760 hours.

[3] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Networks' components causing load loss. Interruptions caused by GLPL's customers are recorded but not charged against GLPL reliability performance for the customer initiating the interruption, but are charged against GLPL reliability performance for other interrupted customers.

3. Performance Standards to Identify Performance "Outliers"

The Hydro One minimum standard of performance will be used as triggers by GLPL to initiate technical and financial evaluations with affected customers. GLPL is committed to compare GLPL delivery point performance against the Hydro One delivery point performance standards in 2009, when GLPL has five (5) years of data. Further to the Board's direction referenced in section 1 above, GLPL will review its decision to commit to the Hydro One standards.

At least until that time, the Hydro One minimum standard of performance will apply to all existing GLPL transmission load customers. For new or expanding customer loads, the delivery point performance requirements will be specified and paid for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement (CCRA).

When the three year rolling average of delivery point performance falls below the minimum standard of performance (i.e. performance "outlier") or when delivery point customers indicate that analysis is required, GLPL will initiate technical and financial evaluations to determine the root cause of unreliability and if any remedial action is required to improve reliability.

4. Performance Standards to Identify Performance "Inliers"

The performance standard to maintain the historical reliability performance levels at each customer DP will identify customer delivery points with deteriorating trends in reliability performance (i.e. performance "inliers") notwithstanding the fact that they are satisfactory performers as outlined in section 3. Specifically, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is to be set at each delivery point, based on that delivery point's fixed 10 year 2004 to 2013 average performance, plus one standard deviation (1σ). The performance baseline triggers are to include forced outages resulting from force majéure events, but exclude events which have excessive impact on the transmission system that in GLPL's assessment, strongly skew the historical trend of the measure e.g. tornadoes, earthquakes, other acts of God and any other significant event having "excessive" impact on performance that is beyond the reasonable control of, and not a result of the fault or negligence of GLPL.

Until GLPL has 10 years of data, GLPL will treat existing customers and new/modified customers by excluding them from identification as an "inlier" until a minimum of 5 years of data is available to establish the baseline triggers. The baseline triggers for these delivery points will be updated each year until 10 years of performance data is available. DP performance that is worse than either baseline trigger (frequency or duration) in two consecutive years will be a candidate for remedial action. GLPL will respond by initiating technical and financial evaluations with affected customers to determine the root cause of the unreliability and remedial measures required to restore the historical reliability of DP performance.

Further to the Board's direction referenced in section 1 above, GLPL will analyze the data after 5 years of data is available for existing customers and will review its decision to commit to the "inlier" standard.

As a result of insufficient statistical data during the 2007 to 2009 period, deteriorating performance will be monitored but no delivery point will be classified as an "inlier". During this period, GLPL shall meet annually with each existing customer to review DP performance and to initiate remedial action when the root cause is within GLPL's control[4].

5. Remedial Costs to Address Performance "Outliers and Inliers"

As specified by the Code, GLPL will not attribute the costs associated with network investment to any customer. Any variance from that approach requires a determination of the Board further to a request by any party, including GLPL.[5]

GLPL does not charge customers for the cost of the initial technical and financial evaluation. The cost to prepare the final estimate is the only portion of the technical and financial evaluation that is included as part of the cost of the remedial work.[6]

GLPL will cover the remedial costs, including appropriate asset maintenance costs which include on-going maintenance and asset replacement to restore/sustain the inherent reliability performance of the existing assets to what was designed originally. These expenditures are made on an ongoing basis consistent with "good utility practices", irrespective of actual delivery point performance or of whether a delivery point is a performance "outlier or inlier". No customer financial/capital contribution is required for these normal maintenance expenditures.[7]

To encourage proceeding with only those reliability performance improvements that are technically and economically practical and to limit the subsidization of reliability improvement costs by other pool customers, GLPL's level of incremental investment for improving the performance of an "outlier or inlier", beyond what was the original design, will be limited to the present value of three years worth of transformation and/or transmission line connection revenue[8] associated with that delivery point. Any funding shortfalls for improving delivery point reliability performance, beyond what was the original design, will be made up by affected delivery point customers in the form of a financial/capital contribution. Cost responsibility for these investments is to be consistent with the new Market Rules and the Transmission System Code. Affected delivery point

[4] Board Decision and Order EB-2006-0201 dated June 6, 2007 section 4 page 7
[5] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.9 page 19
[6] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.9 page 19
[7] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.9 page 20
[8] In the special case where a delivery point pays only network tariffs, transmission line connection tariffs are to be used as proxy in the revenue calculation.

customers will be responsible for all the costs associated with any new/modified facilities required on facilities (lines and stations) they own. The financial/capital contribution requirement is to be detailed in a Connection Cost Recovery Agreement (CCRA) to be signed with the affected customers, before any work to improve delivery point "outlier or inlier" performance begins.

Where specific GLPL transmission facilities are serving two or more customers in common with performance "outlier or inlier" performance, GLPL will approach all affected customers to determine their willingness to contribute jointly.[9]

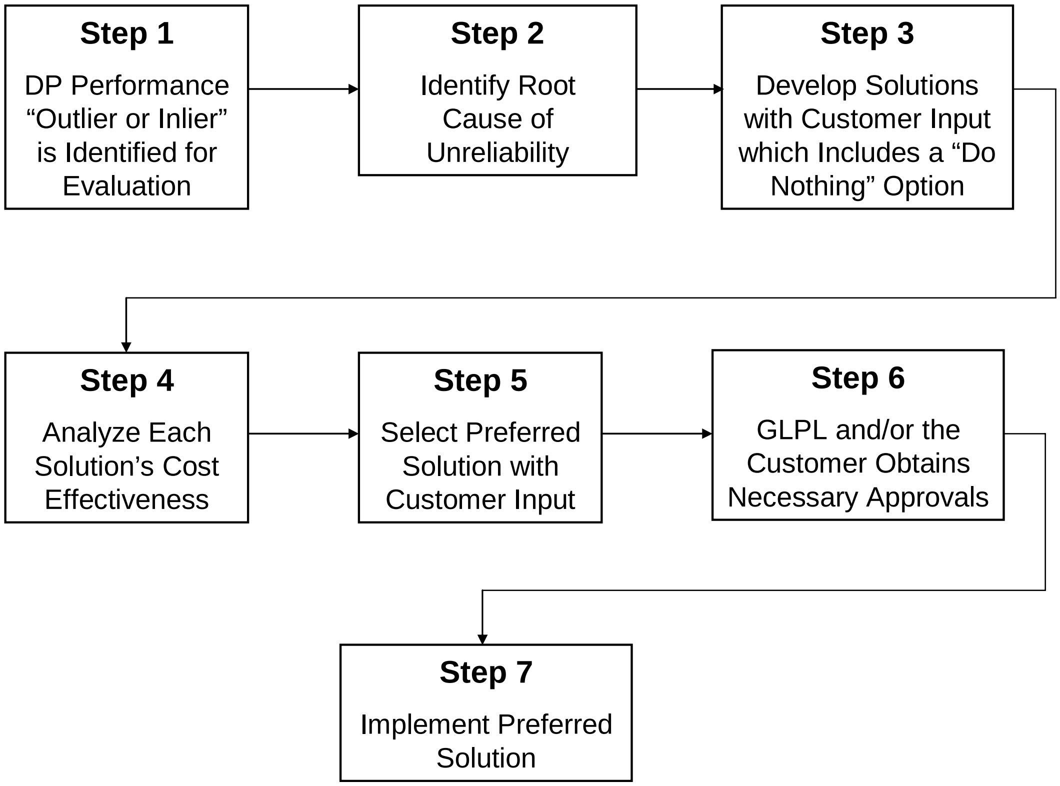
Where a customer contribution is required to improve or expand the transmission system to correct performance "outlier or inlier" performance, the customer will be given the right to undertake contestable work consistent with those applicable to new customer connections in the Code.[10]

When GLPL completes work to restore delivery point performance to standard, it will continue to monitor the delivery point the year after the work is completed. If future performance suggests that the standard has not been met, then GLPL will review the work that has taken place and will identify corrective action, possibly with the financial participation of the customer. GLPL will not as a practice wait another 3 years and start a new technical and financial evaluation. GLPL will review and identify customer delivery point performance annually, regardless of the investment history.[11]

6. Implementation Process to Address Performance "Outliers and Inliers"

The Customer Delivery Point Performance Standards define triggers for GLPL to initiate technical and financial evaluations with affected customers. Each year GLPL reviews reliability performance with its customers based on forced outage statistics which are compiled in January of each year once the previous year's data has been reviewed. For customer delivery points that are identified as performance "outliers or inliers" identified as per section 3 or 4 above, GLPL will negotiate timing, solution, cost sharing arrangement, and any other related matters with each customer wanting to proceed with the delivery point reliability performance improvements based on the process outlined below.

[9] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.12 page 22
[10] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.13 page 23
[11] Board Decision and Order RP-1999-0057 and EB-2002-0404 dated July 25, 2005 section 2.3.19 page 19



Step 1 - DP Performance "Outlier or Inlier" is Identified for Evaluation

GLPL compiles the DP data for each year by the end of January including identifying any "outliers or inliers" that may require a technical and financial evaluation. GLPL will inform each customer of the results where it's DP is an "outlier and/or inlier" and determines with the customer if GLPL will proceed with a technical and financial evaluation. The timing of starting the process for each customer will be discussed with the customer and will be base on prioritizing the "outliers and inliers".

Step 2 - Identify Root Cause of Unreliability
(Timeline: 1 to 2 months)

GLPL will analyze the available data and obtain additional data as necessary to determine if there is a root cause for the unreliability or whether there are several factors.

Step 3 – Develop Solutions with Customer Input which includes a "Do Nothing" Option (Timeline: 1 month)

The data from Step 2 will be discussed with the customer and possible options (including a "do nothing" option) will be developed focused on improving the reliability of the delivery point.

Step 4 - Analyze Each Solution's Cost Effectiveness
(Timeline: 1 month)

Estimated costs of implementing each option are prepared and cost/benefit analysis is undertaken to determine the most cost effective solution. Any cost sharing with the customer is identified for each option.

Step 5 - Select Preferred Solution with Customer Input
(Timeline: 1 to 2 months)

Based on the results of Step 4, the selection of the preferred solution will be discussed with the customer. With respect to any cost sharing the customer will have to agree to pay its share if GLPL proceeds to implement that option as the selected option.

Step 6 – GLPL and/or the Customer Obtain Necessary Approvals
(Timeline: 2 months)

GLPL will then obtain internal approval to proceed with the preferred solution. For "outliers or inliers", where the customer must make a financial/capital contribution, the customer will obtain internal approval to pay the required contribution.

Step 7 – Implement Preferred Solution
(Timeline: To be Determined)

The timing/schedule for the preferred solution will consider customer impacts, nature of the remedial measures, equipment deliveries, GLPL resource capabilities, other investment priorities, and outage/resource availability. Where a customer has the obligation to pay a financial/capital contribution the customer and GLPL will execute a Connection Cost Recovery Agreement (CCRA) prior to commencement of work on the preferred solution.

Note: Timelines are based on dealing with one customer regarding one "outlier or inlier". If more than one customer is involved in dealing with a DP performance issue then the timelines will likely be longer because of the increased complexity of dealing with more than one customer.

BENCHMARKING

The Ontario Energy Board ("OEB") stated in the *Filing Requirements for Electricity Transmission Applications, Chapter 2, dated February 11, 2016 that*

> "*the OEB recognizes that a transition period may better accommodate the gradual entrenchment of RRFE objectives and principles in transmission rate-setting over time. Therefore, where a transmitter is filing based on cost of service or the Revenue Cap index, if benchmarking evidence is not currently available, the transmitter must file in its application a strategy to acquire such evidence for its subsequent application*[1]."

In the Decision and Order in proceeding EB-2016-0356, dated September 28, 2017, it was noted by Intervenors and OEB Staff "*that a Total Factor Productivity ("TFP") study should be completed by Hydro One Transmission for its 2019 Revenue Requirement Application*[2]". Further Hydro One Sault Ste. Marie ("HOSSM") "*noted that Hydro One Transmission will be undertaking a TFP study in connection with its 2019 Revenue Requirement Application. The results of that TFP study are expected to be available to HOSSM*". HOSSM has included in this application, a copy of the *Transmission Study for Hydro One Networks Inc.: Recommended CIR Parameters and Productivity Comparisons* prepared by Power System Engineering, Inc. on behalf of Hydro One as Exhibit D, Tab 1, Schedule 1, attachment 1. HOSSM has used the results from this study

[1] Filing Requirements for Electricity Transmission Applications, Chapter 2, dated February 11, 201, page 2.
[2] Decision and Order in proceeding EB-2016-0356, dated September 28, 2017, page 5.

to support the components of its proposed revenue cap index framework; inflation factor, productivity factor and stretch factor.

As the definition of benchmarking is a standard against which something can be measured or assessed, HOSSM has also provided a proposed scorecard that includes metrics, annual results and proposed targets in Exhibit C, Tab 1, Schedule 1. The annual results of the scorecard metrics have also been provided on graphs to illustrate the year over year trending. Key Performance Indicators ("KPIs") that are currently tracked by HOSSM are also included in the same exhibit.

It is expected that the next application submitted to the OEB will be after HOSSM's integration with Hydro One. At that time, HOSSM will be included as part of Hydro One for any benchmarking studies.

HOSSM will also participate in any benchmarking studies undertaken by Hydro One in which it is requested to do so.

REVENUE CAP IR MECHANISM AND COMPONENTS

1. INTRODUCTION

The revenue requirement for each transmitter is approved by the Ontario Energy Board ("OEB") and is used to set uniform transmission rates that apply throughout the province. The Hydro One Sault Ste. Marie ("HOSSM") application is a Revenue Cap Incentive Rate-setting application ("RCIR"). As detailed in Chapter 2 of the Filing Requirements for Electricity Transmitter Applications, a transmitter can propose an incentive mechanism for adjusting the revenue requirement on an annual basis. A revenue cap refers to the mathematical formula used to set how much a utility's revenue can increase in a year when the utility is not having a full review of its rates through an OEB process. The formula ensures that a utility's rates will increase at a rate which is less than inflation.

An RCIR is an incentive-based approach that includes expectations for the development of an incentive mechanism, as well as productivity and stretch commitments. Transmitters are to propose and substantiate the appropriate method and commitments for these elements. The Transmission Filing Requirements dated February 11, 2016[1], described the purpose of productivity and stretch factors as the "sharing of benefits" for a revenue cap index. Sharing of benefits is to be accomplished by subtracting the productivity and stretch factors from the inflation factor in the revenue cap index formula. The intent is to ensure that customers will share in the benefits derived from transmitters' performance incentives.

[1] Filing Requirements For Electricity Transmission Applications, Chapter 2, Revenue Requirement Applications, dated February 11, 2016, page 5

HOSSM is proposing a revenue cap index framework methodology in this application to determine rates for the years 2019 to 2026 inclusive. HOSSM would continue to use this framework throughout the deferral period by filing annual revenue cap adjustment applications. Once the applicable framework has been approved by the OEB in this proceeding for the deferral period, the subsequent annual applications would set out the relevant calculations on that basis.

In the Decision and Order in proceeding EB-2016-0356, OEB staff, AMPCO, and SEC agreed that a Total Factor Productivity ("TFP") study should be completed by Hydro One Transmission for its 2019 Revenue Requirement Application. Hydro One Networks commissioned Power System Engineering, Inc. ("PSE") to perform a TFP study. The study entitled *Transmission Study for Hydro One Networks Inc.: Recommended CIR Parameters and Productivity Comparisons* can be found as Attachment 1 to this exhibit. As stated in proceeding EB-2016-0356, HOSSM intends to adopt the inflation factor, productivity factor and stretch factor to be submitted into evidence by Hydro One Networks Transmission in proceeding EB-2018-0130 and supported by the TFP study performed by Power System Engineering due to the pending integration.

1.1 INFLATION FACTOR

In the Decision and Order for proceeding EB-2016-0356, the OEB agreed with intervenors, that evidence should be submitted regarding the appropriate weights. As part of the TFP Study, PSE was tasked with providing evidence for revising these weights to align with the electric transmission industry. PSE performed an econometric benchmarking study and a TFP study. Selected results from the total cost and TFP studies were used to determine the appropriate weights to use for the inflation factor.

The PSE recommended inflation factor calculation is based on the sum of the following weightings:

- 86% of the annual percentage change in Canada's Gross Domestic Product-Implicit Price Index, Final Domestic Demand ("GDP-IPI FDD") for Canada as reported by Statistics Canada; and
- 14% of the annual percentage change in the Average Weekly Earnings ("AWE") for workers in Ontario, as reported by Statistics Canada.

The inflation factor is expressed as:

Inflation Factor = (0.14 * growth in AWE) + (0.86 * growth in GDP-IPI FDD)

The latest annual percent change for the GDP-IPI and the AWE for Workers in Ontario was released by the OEB on November 23, 2017 for use in applications for rates effective in 2018.

The derivation of Hydro One Transmission's proposed Inflation Factor is shown in Table 1 below.

Table 1 - Derivation of Inflation Factor

	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Resultant Value - Annual Growth for the 2-factor IPI
Year	Q1	Q2	Q3	Q4	Annual	Annual % Change (A)	Weight (B)	Annual	Annual % Change (C)	Weight (D)	Annual % Change ([A*B]+[C*D])
2015	114.6	115	115.7	116.1	115.35			962.94			
2016	116.4	116.3	116.8	117.5	116.75	1.2%	86%	973.56	1.1%	14%	1.2%

Using PSE's proposed methodology and weightings an Inflation Factor of 1.2% was derived. The Inflation Factor will be updated annually based on the methodology above to reflect the actual annual percent changes for each index that are made available by the OEB.

1.2 PRODUCTIVITY FACTOR

In proceeding EB-2016-0356, HOSSM proposed to use the OEB-approved productivity factor of 0%, as established for distributors in 2017. The OEB responded that the 0% productivity factor was based on a TFP analysis that considered the impact of IFRS, smart meters and Conversation and Demand Management program costs on distributor input data collected over 10 years and therefore the OEB could not find that the 0% productivity factor for distributors should be applicable to HOSSM in 2017 without better evidence of its applicability to transmitters.

Supported by the TFP Study, PSE recommends an X factor of 0.0%. This is based on the negative industry TFP finding of -1.71%. In previous Decisions, the OEB found that a negative X factor embedded within the escalation formula was inappropriate. Therefore, PSE recommends a 0.0% X factor. PSE also notes that the difference between the industry TFP trend and the X factor should be considered as an "implicit stretch factor". Hydro One and HOSSM will be expected or "stretched" to outpace the industry's historical TFP by 1.71%. This would be an extraordinarily large Productivity factor value.

1.3 STRETCH FACTOR

In proceeding EB-2016-0356, HOSSM proposed a stretch factor of 0%. The OEB found the benchmarking evidence insufficient to support the submission that HOSSM is in the top cohort of efficiency. HOSSM then indicated they would adopt the stretch factor that Hydro One Transmission proposes in its 2019 revenue requirement application (EB-2018-0130).

Supported by the TFP Study, PSE recommends a stretch factor of 0.0%. There are two reasons for this recommendation. The first is the "implicit Productivity factor" of 1.71%, described in Section 1.2 above. The second reason is the total cost benchmarking result shows Hydro One is 31.8% below its benchmark costs throughout the test year period for Hydro One Transmission's rate application (2019 to 2022). PSE notes that in 4^{th} Generation Incentive Rate-setting a benchmark finding of -31.8% would imply a stretch factor of 0.0%. Given the strong cost performance, PSE believes a stretch factor of 0.0% is warranted.

1.4 REVENUE CAP INDEX FRAMEWORK

HOSSM proposes a revenue cap index framework where the allowed rate of change in the price of regulated services will be adjusted by the growth in an inflation factor minus an X-factor. The X-factor is comprised of a productivity component and a stretch factor. The productivity factor is intended to be the external benchmark which all distributors are expected to achieve, using estimates of the long-run trend in TFP growth for the regulated industry as typically measured. The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that transmitters are expected to achieve under Incentive Rate-setting.

Therefore HOSSM proposes the revenue cap index expressed as:

(i) Inflation Factor = (currently) 1.2%

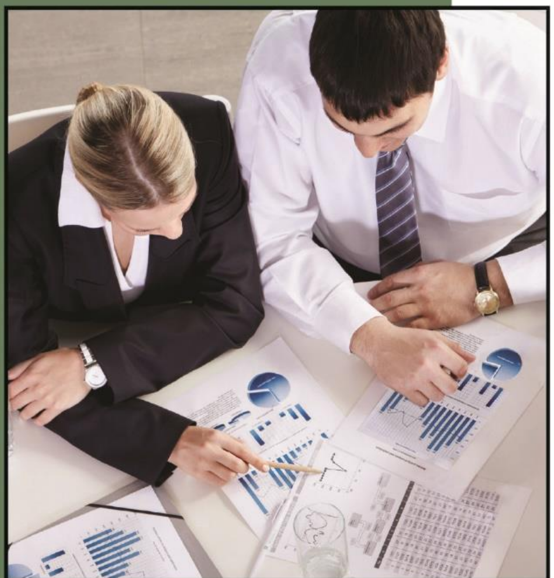
(x) Productivity Factor + Stretch Factor = 0% + 0%

$$Revenue\ Adjustment = i - X$$

Therefore, the proposed revenue requirement for 2019 using current parameters would be 1.2%. This will be updated once the revised parameters are released the OEB; expected in Q4 of 2018.

Power System Engineering, Inc.

Full-service consultants



Transmission Study for Hydro One Networks Inc.:

Recommended CIR Parameters and Productivity Comparisons

Prepared by:

Power System Engineering, Inc.

May 23, 2018

Transmission Study for Hydro One Networks Inc.:

Recommended CIR Parameters and Productivity Comparisons

<u>Authors</u>

Steven A. Fenrick, M.S.

Erik S. Sonju, P.E.

Contact: Steve Fenrick
fenricks@powersystem.org

Direct: 608.268.3549

Mobile: 608.334.5994

1532 W. Broadway
Madison, WI 53713

www.powersystem.org

Table of Contents

List of Tables

List of Figures

1 Executive Summary

1.1 Overview of Study

Power System Engineering, Inc. (PSE) was engaged by Hydro One Networks, Inc. (Hydro One) to conduct an empirical study of Hydro One's transmission operations. The three main areas studied were:

1. Total cost levels,
2. Total factor productivity (TFP) trends, and
3. Custom incentive regulation (CIR) parameters.

Results from the first two areas (total costs and TFP) informed the recommended CIR parameters.

For the first area, PSE conducted an econometric benchmarking study of Hydro One's total costs. For the second area, TFP, we calculated the TFP trend of both Hydro One and that of the U.S. electric transmission industry. To develop recommendations for Hydro One's CIR parameters, PSE used selected results from the total cost and TFP studies, and determined the appropriate weights to use for the inflation factor. PSE used the results of the study to:

- Make recommendations regarding the custom incentive regulation (CIR) parameters that should be used in Hydro One's CIR application, and
- Assist the Ontario Energy Board (the Board) and stakeholders in assessing the reasonableness of the projected transmission cost levels contained in Hydro One's CIR application.

The following table specifies which study items are used to formulate the specific CIR recommendations.

Table 1 Research Items

Research Item	Used for:
1. Econometric Total Cost Benchmarking	Developing a stretch factor recommendation and assessing historic and projected CIR cost levels.
2A. Industry TFP Trend	Developing an X Factor recommendation in the CIR plan.
2B. Hydro One TFP Trend	Assessing the projected CIR cost levels and how the TFP trend for Hydro One compares to the historical norm for the industry.
3. Labour and Non-Labour Split	Inflation Factor recommendation

The report results should be helpful to stakeholders in assessing the reasonableness of the projected spending levels of Hydro One's transmission operations. The total cost benchmarking shows how Hydro One's total costs compare to the industry's costs, after empirically adjusting for service territory differences. The TFP trends of Hydro One and the industry provide the ability to compare how Hydro One's TFP has changed over time, relative to how the industry's TFP has changed. Stakeholders can also examine Hydro One's anticipated TFP trend during the CIR period, and compare that TFP trend to the industry's historical TFP trends.

In the three sub-sections that follow (1.1.1, 1.1.2, and 1.1.3) we give a brief overview of the three main study areas. In subsequent sections (1.2, 1.3, and 1.4) we provide an overview of the research findings in the study areas.

1.1.1 Econometric Cost Benchmarking Research: Overview

The econometric total cost benchmarking research is used as the basis for the stretch factor recommendation and to assist the Board and stakeholders as they evaluate the spending levels of Hydro One. The use of econometric total cost benchmarking research to set stretch factors for electric distributors was established by the Board's Decision in the 4th Generation Incentive Regulation (4GIR) proceeding (EB-2010-0379).[1] PSE has modified the variables and sample to accommodate a transmission total cost econometric study. We have retained the basic benchmarking methodology of the 4GIR proceeding.

1.1.2 TFP Research: Overview

The industry TFP trend research is used as the basis for the X Factor recommendation. The 4GIR Decision used industry-wide TFP to establish the X Factor for distributors' price cap formulas. Similarly, Hydro One's revenue cap formula should also include an X Factor based on an estimate of electric transmission industry-wide TFP. The economic theory for the revenue cap formula is provided in Section 2.

After the industry TFP trend is established, the Hydro One TFP trend research is used to compare the company's own TFP trend to that of the industry. PSE's research provides the Board and stakeholders with the historical and projected TFP trends of Hydro One. However, for any given utility, the company's own TFP trend should not be used in setting its X Factor. Incentive regulation principles dictate that a proper analysis should use an industry TFP measure that is largely external to the utility to which it is being applied.

The historical period for both the benchmarking and TFP studies is 2004 to 2016. Hydro One projections are shown from 2017 to the end of the CIR period in 2022.[2] The industry sample is

[1] November 21, 2013, EB-2010-0379, *Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors.*

[2] 2017 actual costs have been inserted for Hydro One, but other variables are based on projections for 2017.

composed of 56 United States transmission investor-owned utilities for the benchmarking sample and 47 utilities for the TFP sample.[3]

1.1.3 CIR Inputs: Overview

In this report, PSE makes recommendations for the factors in the CIR formula, including the inflation factor, the X factor, the output growth factor, and the stretch factor. One important aspect of the inflation factor is the labour/non-labour split.

In the Board's September 28, 2017 Decision for Hydro One Sault Ste. Marie, LLP (Hydro One SSM) regarding the company's application for electricity transmission, the Board stated that evidence on the appropriate input weights for the inflation factor should accompany future rate applications by Hydro One SSM.[4] In the Hydro One SSM application, the company put forth the same input weights as used for the distributors in 4GIR. The distributors' inflation factor has a 70% weight on non-labour and a 30% weight on labour. PSE was tasked with providing evidence for revising these weights to better align with the electric transmission industry.

To accomplish this task, PSE estimated the annual labour costs in the benchmarking sample. We then divided the estimated labour costs by the total costs for each observation and took an average of this percentage. Our findings suggest a 14% weight on the labour component and an 86% weight on the non-labour component.

1.2 Total Cost Benchmarking: Findings

Using a sample of 57 transmission utilities, PSE estimated a translog total cost econometric model that captures the relationship between total transmission costs and a set of variables. The variables are described in Section 3.2 . As required by accepted best practice, all first order variables are signed according to theory and are statistically significant at a 90% level of confidence.[5] PSE applied the translog functional form, which is the same functional form we used in Hydro One's distribution total cost benchmarking study.[6] However, the explanatory variables are different, and

[3] With Hydro One included, the number is 57 utilities in the benchmarking sample and 48 in the TFP sample. The TFP sample is smaller than the total cost benchmarking sample, because for the TFP analysis, utilities need an observation in every single year of the sample period. In other words, for TFP analysis we need a balanced panel—we could not use any utility that had missing data in any one of the years 2004-2016. This contrasts with the benchmarking model where, if data is unavailable for a specific year for a specific utility, that year can be omitted (while still using other years for that utility), resulting in an unbalanced panel estimation. All utilities in the TFP sample are also in the benchmarking sample.

[4] EB-2016-0356, *Decision and Order* dated September 28, 2017, p. 5.

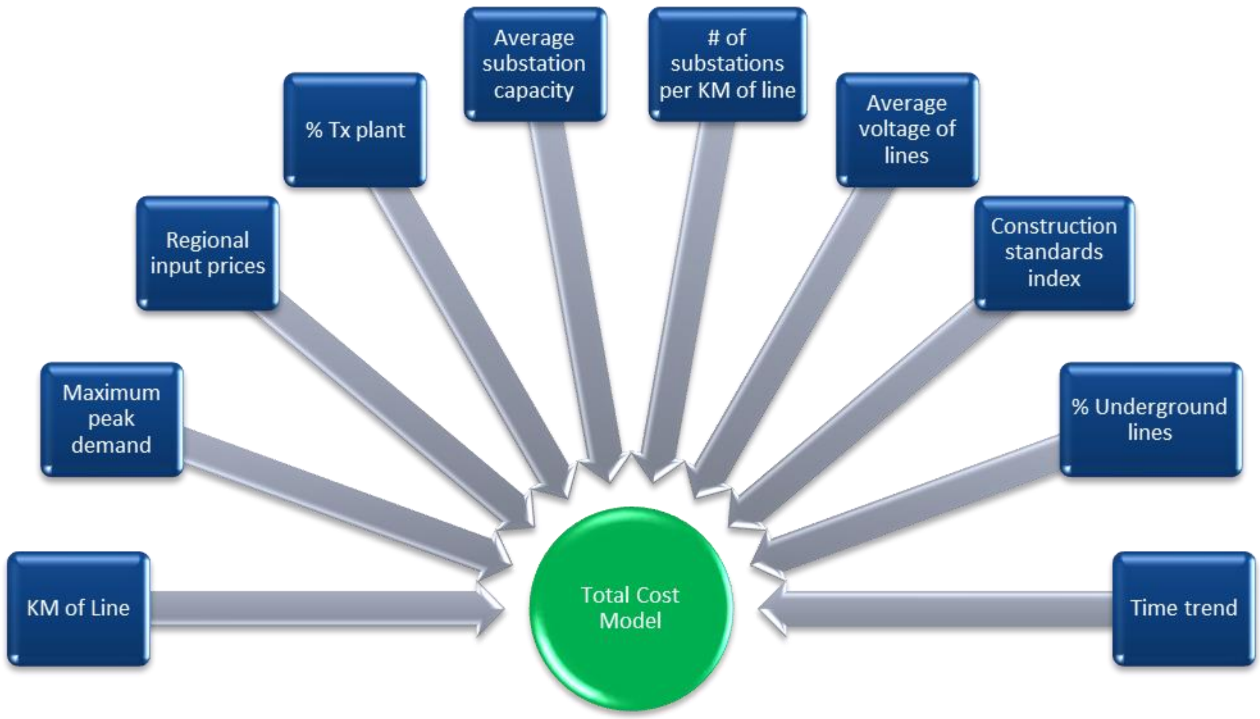
[5] In fact, all first order variables in the model are statistically significant at the 99% confidence level.

[6] This report can be found in case EB-2017-0049. The PSE report is titled, *Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network (Updated with 2016 Actual Hydro One Data and Projections to 2022)*. May 18, 2017.

the distribution sample included numerous U.S. rural electric cooperative distributors to help capture the impacts of a distribution system serving low customer density areas.

The variables included in the total cost model are illustrated in the following figure. These variables (also known as cost drivers) are included in the total cost model to correlate total cost with the variables and enable adjustments for the specific service territory circumstances encountered by Hydro One. For a more detailed description of the included variables, please see Section 3.2.

Figure 1 Total Cost Model Variables



The benchmark scores are derived by taking the logarithmic percentage difference between Hydro One's actual total costs and their model-predicted total costs. A negative number implies that the company's actual costs are lower than the benchmark (i.e., lower than expected for an average utility with that company's operating circumstances). Table 2 and Figure 2 show Hydro One's scores for the historical and projected years.

Table 2 Hydro One's Cost Performance 2004-2022

Year	Hydro One Actual Costs (Thousands, C$)	Hydro One Benchmark Costs (Thousands, C$)	% Difference (Logarithmic)
2004	$1,321,847	$1,607,757	-19.6%
2005	$1,374,866	$1,729,615	-23.0%
2006	$1,456,209	$1,844,035	-23.6%
2007	$1,589,793	$1,996,161	-22.8%
2008	$1,672,186	$2,200,213	-27.4%
2009	$1,786,248	$2,293,710	-25.0%
2010	$1,808,049	$2,310,014	-24.5%
2011	$1,987,327	$2,568,490	-25.7%
2012	$2,115,512	$2,723,021	-25.2%
2013	$2,100,004	$2,703,669	-25.3%
2014	$2,123,453	$2,765,321	-26.4%
2015	$2,230,624	$2,908,015	-26.5%
2016	$2,283,979	$3,047,901	-28.9%
2017 (projected)	$2,338,963	$3,174,800	-30.6%
2018 (projected)	$2,430,797	$3,323,325	-31.3%
2019 (projected)	$2,511,095	$3,447,400	-31.7%
2020 (projected)	$2,600,683	$3,573,281	-31.8%
2021 (projected)	$2,695,299	$3,706,040	-31.8%
2022 (projected)	$2,797,680	$3,843,932	-31.8%
Average % Difference			
2014-2016			**-27.3%**
2019-2022			**-31.8%**

Figure 2 Hydro One's Cost Performance 2004-2022

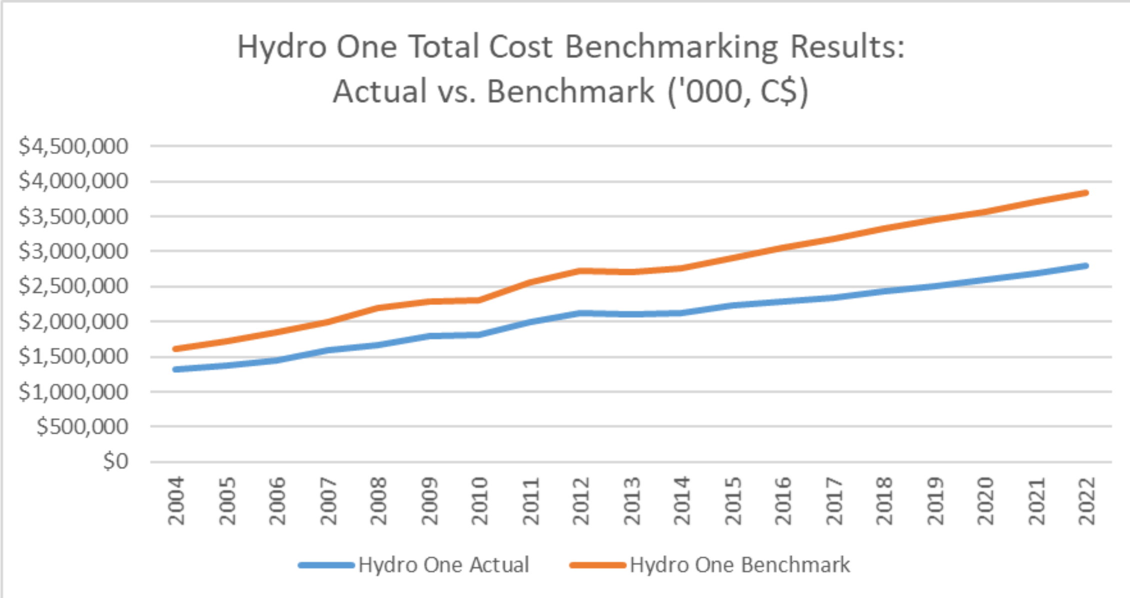


Table 2 and Figure 2 show that Hydro One's total costs have been below the benchmark value since 2004. In 2016, Hydro One is more than $700 million below its benchmark total costs. This difference in Hydro One's actual to benchmark costs is projected to increase to over $1,000 million by 2022, assuming Hydro One's application is approved in full. Throughout the 2019-2022 CIR period, Hydro One's projected total costs are 31.8% below benchmark expectations.

1.3 TFP Findings: Industry and Hydro One

Using a sample of 48 transmission utilities, PSE calculated the total factor productivity trend of the industry from 2004 to 2016. This twelve-year period showed an average annual decline in industry-wide TFP, with an annual growth rate of -1.71%.

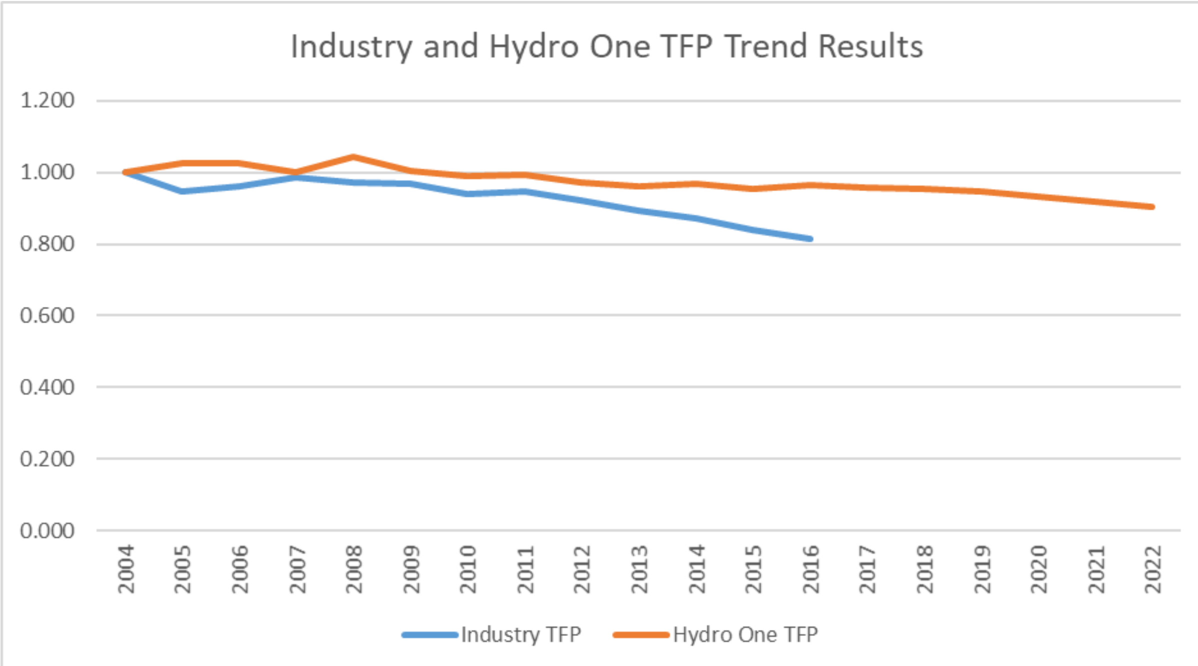
Hydro One's own TFP from the 2004 to 2016 period declined, but at a much slower pace than the industry, with an average annual growth rate of -0.31%. Hydro One's TFP is projected to decrease during the CIR period of 2019 to 2022, with an average annual growth rate of -1.43%. Hydro One's TFP trend is lower in the CIR period; however, Hydro One's lower TFP trend (-1.43%) is still outpacing the historic industry TFP trend of -1.71%.

The TFP results and average annual growth rates are provided in the table and figure following.

Table 3 Industry TFP and Hydro One TFP

Year	Industry TFP Index	Hydro One TFP Index
2004	1.000	1.000
2005	0.945	1.026
2006	0.963	1.024
2007	0.987	1.000
2008	0.971	1.042
2009	0.967	1.003
2010	0.940	0.992
2011	0.946	0.992
2012	0.922	0.971
2013	0.893	0.962
2014	0.871	0.967
2015	0.841	0.956
2016	0.814	0.964
2017 (projected)	NA	0.958
2018 (projected)	NA	0.954
2019 (projected)	NA	0.945
2020 (projected)	NA	0.933
2021 (projected)	NA	0.920
2022 (projected)	NA	0.906
Average Annual Growth Rate		
2004-2016	**-1.71%**	**-0.31%**
2010-2016	**-2.40%**	**-0.47%**
2019-2022	**NA**	**-1.43%**

Figure 3 Industry TFP and Hydro One TFP



Hydro One's TFP trend compares favorably to the industry trend. Hydro One's annual TFP trend is 1.41% higher than the industry TFP trend from 2004 to 2016. Hydro One's projected TFP from 2019 to 2022 remains 0.28% higher than the long-run historical industry trend. The industry has had a consistent decline in TFP since 2004. In Section 6.1, we address some possible causes for negative TFP growth.

1.4 PSE CIR Parameter Recommendations

PSE recommends the following general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$$Growth\ Revenue = Inflation - X - Stretch\ Factor + Capital\ Factor \quad \text{[Equation 1]}$$

The specific parameter values for each component are as follows:

- PSE recommends a two-factor **inflation factor** comprised of input weights of 14% labour and 86% non-labour. In 4GIR for the electric distribution industry, the inflation factor grows by 30% of the growth in Average Weekly Earnings (AWE) for Ontario, and 70% of the growth in GDP-IPI FDD. The AWE accounts for the labour component of total costs and the GDP-IPI FDD accounts for the non-labour component. However, this 4GIR weighting needs to be updated for transmission operations. With the transmission weighting of 14% and 86%, historically the inflation factor would grow a bit slower than under the distribution 4GIR weights.

- The PSE **X factor** recommendation is 0.0%. This is based on the negative industry TFP finding of -1.71%. While a negative X factor could be considered, the 4GIR Decision made clear the Board did not desire to have a negative X factor embedded within the escalation formula. For this reason, PSE recommends a 0.0% X factor, which is the same X factor that is found in 4GIR. However, the difference between the industry TFP trend and the X factor should be considered as an "implicit stretch factor". In other words, Hydro One will be expected or "stretched" to outpace the industry's historical TFP by 1.71%. This would be an extraordinarily large stretch factor value.

- The PSE **stretch factor** recommendation is 0.0%. There are two reasons for this recommendation. The first is the "implicit stretch factor" of 1.71%, which is due to the X factor being set at 0.0%. The second reason is the total cost benchmarking result that shows Hydro One is 31.8% below its benchmark costs throughout the CIR period. PSE notes that in 4GIR a benchmark finding of -31.8% would imply a stretch factor of 0.0%. Given the strong cost performance and the large implicit stretch factor, PSE believes a stretch factor of 0.0% is warranted.

- PSE recommends not including an **output growth factor** to simplify the revenue cap formula. While mathematically an output growth factor should be included within the formula (as we will show in Section 2), the measured outputs in this study are unlikely to measurably grow during the CIR period. The output factor would be very close to 0.0% for every year. Additionally, the inclusion of the capital factor to the formula should capture the expected capital cost impact of output growth.

- The **capital factor** is based on Hydro One's proposed capital spending needs. PSE is not making any recommendations regarding the magnitude of the capital factor. We do, however, insert the proposed capital spending amounts into the TFP and total cost benchmarking studies, so the Board and stakeholders can ascertain the projected TFP trends and total cost benchmarking scores that result from the proposed level of capital spending. As is seen in those evaluations, the proposed capital spending by Hydro One compares favorably to the industry. The TFP trend during the CIR period continues to exceed the historic TFP trend of the industry, and Hydro One's projected total costs are 31.8% below its benchmark values throughout the CIR period.

The methodology used to arrive at Equation 1 is shown in the following section.

2 The Revenue Escalation Formula

Since so much of this study ultimately relates to the custom IR process, a brief overview of the mathematics underlying the general revenue escalation formula is warranted. This section gives a general equation for a generic revenue escalation formula and explains how this formula was determined. Subsequent sections discuss total cost benchmarking (Sections 3 and 5) and TFP research (Sections 4 and 6), and the results for those sections are used in CIR recommendations.

2.1 Derivation of the Formula

In the previous section, we recommended the following equation as the general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$$Growth\ Revenue = Inflation - X - Stretch\ Factor + Capital\ Factor \quad \text{[Equation 1]}$$

This section shows how Equation 1 was determined.

The allowed revenue escalation within the revenue escalation formula should mimic the expected growth in costs. Production theory postulates that there should be three main components within the escalation formula. These three components are: input price inflation (I), a productivity expectation (X), and output growth (O).

$$Growth\ Revenue = I - X + O \qquad \text{[Equation 2]}$$

The mathematical derivation of Equation 2 is provided below. It begins with the assumption that the allowed growth in revenue should be equal to the expected growth in costs.

$$Growth\ Revenue = Growth\ Cost \qquad \text{[Equation 3]}$$

Basic production theory states that costs equal the product of input prices and input quantities (Q). In turn, the growth in costs will equal the growth in input prices (I) plus the growth in input quantities.

$$Growth\ Cost = I + Growth\ \mathrm{Q} \qquad \text{[Equation 4]}$$

If we add and subtract the same term to the right-hand side of the equation, that is the same as adding zero, and the equation remains unchanged. We will both add and subtract output growth (O) to Equation 4 to develop Equation 5 below.

$$Growth\ Cost = I + Growth\ Q + O\ - O \qquad \text{[Equation 5]}$$

As we will further discuss in Section 4 on the TFP methodology, the TFP trend is defined as the change in output quantity minus the change in input quantity. In equation form:

$$TFP\ trend = O - Growth\ Q \qquad \text{[Equation 6]}$$

We can rearrange the terms in Equation 5 to the following equation.

$$Growth\ Cost = I - (O - Growth\ Q) + O \quad \text{[Equation 7]}$$

And then insert Equation 6 into Equation 7.

$$Growth\ Cost = I - TFP\ trend + O \qquad \text{[Equation 8]}$$

The last step in getting to Equation 2 is to insert Equation 3, redefine the TFP trend and call it X.

$$Growth\ Revenue = I - X + O \qquad \text{[Equation 9]}$$

A "stretch factor" is sometimes added to the escalation formula to challenge (or stretch) the utility to achieve TFP gains above and beyond the industry TFP expectation. A positive stretch factor slows allowed revenue growth in a manner that shares with customers the financial benefits of the utility exceeding the industry TFP trend. Within 4GIR, the stretch factor is informed by econometric total cost benchmarking evidence, because an inefficient firm can more easily cut costs and ramp up TFP trends than an efficient utility can.

Once we insert the stretch factor (SF) term, we have the following equation.

$$Growth\ Revenue = I - X - SF + O \qquad \text{[Equation 10]}$$

As stated in Section 1.4 the output growth factor (*Growth O*) will be close to zero every year (see Table 8). For example, average annual growth rates from 2019 to 2022 of KM of Line, Maximum Peak Demand, and Output Quantity Index are 0.01%, 0.00%, and 0.01%, respectively. Furthermore, the existence of a Capital Factor should capture the anticipated capital cost impacts of output growth. Thus, if we drop the output term from the equation we get:

$$Growth\ Revenue = I - X - SF \qquad \text{[Equation 11]}$$

Hydro One is proposing to add a Capital Factor term that accounts for additional capital spending.

When this term is added, we arrive at the following equation, which was the recommendation in Section 1.4 .

$$Growth\ Revenue = I - X - SF + Capital\ Factor \quad \text{[Equation 12]}$$

2.2 Discussion of the Specific Values of Each Term

2.2.1 Inflation Factor

The input price inflation index measures the annual external market increase in the price of inputs used within the operations of the utility. The inputs are labour and non-labour. In the 4GIR decision, the index used to measure labour inflation was the Average Weekly Earnings (AWE) for Ontario, published by Stats Canada. The index used to measure non-labour was the Gross Domestic Product-Implicit Price Index, Final Domestic Demand (GDP-IPI FDD) for Canada.[7] For the distributors, the weighting in the 4GIR is 30% on AWE and 70% on GDP-IPI FDD. These two metrics are defined as follows:

1. **AWE:** Annual percentage change in average weekly earnings for all employees in Ontario (from Statistics Canada CANSIM Table 281-0027, available in early April). The annual percentage change will be from the year prior to two years prior.

2. **GDP-IPI:** Annual percentage change in the GDP-IPI FDD for Canada (from Statistics Canada CANSIM Table 380-0066). The annual percentage change will be from the year prior to two years prior.

For the transmission inflation factor, PSE recommends the exact same calculation procedures for the individual labour and non-labour indexes as implemented in the 4GIR distribution inflation formula, but with different weights. Based on the available evidence from the benchmarking sample, we recommend a 14% weighting on AWE and an 86% weighting on GDP-IPI FDD (see Section 7 for a description of how the 14% was calculated). The recommended inflation factor calculation is described as follows:

Inflation Factor = (0.14 * growth in AWE) + (0.86 * growth in GDP-IPI FDD)

2.2.2 X Factor

The X Factor should be based on an external measure of the industry TFP trend. The utility that it is being applied to should have no (or very little) impact on the measured industry TFP trend. This is because incentive regulation seeks to decouple the link between a utility's cost increases to the

[7] November 21, 2013, *EB-2010-0379 Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 11.

allowed revenue escalation. If a utility's own TFP is used within the formula, it will significantly weaken the incentives to enhance productivity and reduce costs.

The TFP industry trend from 2004 to 2016 is declining, with an average annual growth rate of -1.71%. This negative growth rate also declined in a more recent time frame, with a growth rate of -2.40% in the 2010 to 2016 period.

Given the negative productivity findings within the electric transmission industry, combined with the 4GIR decision that stated the Board's desire for a non-negative X Factor, PSE recommends a 0.0% X Factor.

However, we note that this recommendation of 0.0%, instead of -1.71%, implies that Hydro One will need to exceed the historic industry TFP trend by 1.71% during the CIR period in order to achieve the allowed rate of return implicit in the escalation formula. This difference should be thought of as an "implicit stretch factor".

X Factor = 0.0%

2.2.3 Stretch Factor

The stretch factor is an additional term inserted into revenue or price caps to "stretch" the utility into exceeding the industry expected productivity growth of the X factor. It provides ratepayers with an assurance that revenues will grow slower for them than the growth that would occur because of the historical industry productivity value. Often this stretch factor is set based on cost benchmarking studies that provide evidence of the cost efficiency levels of the utility. A utility found to be inefficient will have an easier time cutting costs and increasing its productivity than a more efficient utility.

The recommended X Factor of 0.0% is already considerably higher than the industry TFP trend. This challenging expectation of beating the industry TFP trend is coupled with the total cost benchmarking finding in this report, which finds Hydro One's transmission total costs are 31.8% below benchmarking expectations during the CIR period. In other words, the benchmarking result indicates that Hydro One's cost efficiency appears to be far better than that of the industry. For these two reasons, PSE recommends a stretch factor of 0.0% for Hydro One.

Stretch Factor = 0.0%

2.2.4 Growth in Output

The last term in the revenue escalation formula is the growth in output. This term is not included for price cap indexes, because output growth will automatically increase revenues; this is because a utility's revenues are prices multiplied by billing determinants. However, as we showed in the index formula at the beginning of this section, in a revenue cap context the output growth term should be considered.

However, it is likely that this output growth term will be very close to zero in the CIR period (see Table 8). The flat or declining nature of peak demands, due to conservation and demand management (CDM) plans and energy efficiency technology gains, makes it very likely that the maximum peak demand will be flat. Further, the total kilometres (KM) of transmission lines are projected by Hydro One to remain very close to current levels. Thus, the output growth rate will be essentially zero for each year of the CIR period.

The existence of the capital factor is another reason we recommend not including the output growth factor in the formula. The capital factor incorporates any expected capital costs resulting from output growth. This makes including the output factor somewhat redundant when the capital factor is also present in the formula. However, PSE felt it was important to mention this output growth term in the discussion, for the sake of accuracy and completeness. In the case of a revenue cap formula where the output growth factor is not expected to be zero and a capital factor is not present, an output growth factor should be included in a revenue adjustment formula.

Output Growth = Not included in formula

3 Total Cost Benchmarking Process, Dataset, Variables, and Model Details

The purpose of PSE's benchmarking analysis is to benchmark Hydro One's historical and projected total transmission costs and provide a recommendation on the appropriate stretch factor to apply to Hydro One's incentive regulation application.[8] The benchmark analysis is done by comparing Hydro One's *actual* total cost values (or its projected costs) with the benchmarking model's *predicted* values.[9]

When conducting a benchmarking evaluation, PSE recommends the econometric approach instead of basic peer group comparisons, because in most cases the econometric benchmarking method is more accurate. The econometric benchmarking method has the following advantages:

(1) The ability to statistically test candidate variables,
(2) The ability to statistically test results,
(3) The capacity to include a relatively large number of variables in the analysis, and
(4) It does not require the researcher to subjectively choose a peer group.

When comparing actual cost values with benchmarked (predicted) values, we use the logarithmic percentage difference of Hydro One's actual or projected total costs and the predicted total costs.[10] A percentage difference finding below zero implies Hydro One's costs are below the benchmark level (i.e., a negative value implies that Hydro One's actual total costs are lower than expected).

$$\%\,Difference = Natural\ Log\ \left(\frac{Actual\ Total\ Cost}{Benchmark\ Total\ Cost}\right)$$

To arrive at the predicted (benchmarked) costs for a utility, PSE uses historical cost data from a U.S. dataset comprised of multiple utilities to create a model; this model relates cost to certain variables for the industry as a whole.

The process takes publicly available variable data for each utility in the dataset (such as KM of line, maximum peak demand, wage levels, etc.), and creates a model that in a sense describes the

[8] Hereafter, when we use the term "costs" or "total costs," we are referring to transmission costs, unless otherwise stated.

[9] In this report we will use "predicted," "expected," or "benchmark" costs to refer to the econometric model's outputs for those metrics. Note that the word "predicted" could refer to historical costs (e.g. "the model predicted that an average utility with these specific operating characteristics would have had costs of $X in 2007, but actual costs in 2007 were $Y"). We will use "forecasted costs" or "projected costs" to refer to Hydro One's estimates of total costs in future years, in this case 2018-2022. Therefore, in future years, we are comparing the model's expected (predicted) costs with Hydro One's forecasted (projected) costs. Other variables/model input values such as "KM of transmission lines" may also have "projected" or "forecasted" values.

[10] We use the logarithmic percentage rather than the arithmetic percentage because it is the convention within the benchmarking industry and the method used in 4GIR.

industry as a whole (the "industry" in this case is comprised of the utilities in the dataset). This model can then be used to predict the expected costs for each utility for any given year, given the specific variable data for that utility.[11] For future years, projected values for Hydro One costs, and for other variables, are used in a similar manner.

The expected costs (benchmark costs) for a given utility represent the costs we would expect from that utility, given its specific variable data, if that utility were an "average" performer. Thus, for any utility in the dataset, actual or projected costs can be compared to expected costs, and this comparison can be made for any given year.[12] In this report, the model is used to produce Hydro One's "expected" (benchmarked) total transmission costs.

The general approach of our benchmarking analysis is as follows:

1. PSE assembled the historical costs of all utilities in the dataset, along with the variables that affect cost, such as KM of transmission lines, average voltage of lines, maximum peak demand, wage levels, etc.
2. Using the historical data (and projected data for Hydro One), PSE estimated an econometric model that expresses the relationship between the variables and cost.
3. PSE can then produce "benchmark" values for a given utility. The benchmark values are determined from the model, using the specific variable values for a given year. In Hydro One's case, the benchmark represents the total cost amount expected for an average-performing utility with the same variable values faced by Hydro One.
4. We then compare the total costs that are expected (predicted) by the model to Hydro One's actual historical and projected costs, which allows us to: (1) evaluate the historical and projected cost performance, and (2) recommend a stretch factor. This process is performed for specific years; e.g. we can compare Hydro One's expected 2015 costs with its actual 2015 costs.

The process for future years is similar to the process for past years. Hydro One has total transmission cost projection estimates for 2018-2022. Those projected costs can be compared to the model's predicted costs for those years. Variable data for 2018-2022 is also projected (using Hydro One estimates or third-party sources).

[11] A complete list of variables used in the model appears later, in Section 3.2 below.

[12] Again, "projected" refers to Hydro One's estimates of what its actual costs will be from 2018-2022; "expected" refers to values that the model produces ("expected" values could refer to previous years or future years).

3.1 Summary of Dataset

3.1.1 Econometric Benchmarking Requires a Robust Dataset

Econometric benchmarking of Hydro One's transmission costs requires a robust dataset, with multiple transmission utilities, over multiple years, with publicly available information on annual explanatory variables and output. Furthermore, the definitions used in the variables and output should be consistent across all the utilities in the dataset. For example, the various sub-categories of transmission expenses should be similar across the utilities in the dataset; otherwise, we cannot be sure that utilities are classifying costs in the same manner.

Hydro One provides transmission service for most of Ontario, and so an Ontario-only dataset would mostly consist of Hydro One data. Therefore, an Ontario-only dataset would not be sufficient.

3.1.2 The Necessary Data is Not Available for Most Canadian Utilities

PSE investigated whether the dataset could include Canadian transmission utilities from other provinces. However, most other Canadian transmission utilities are not compelled to publicly file the information necessary to analyze consistently defined cost categories and consistently defined output and explanatory variables.

However, U.S. utilities are required to file FERC Form 1s that contain variable and output data defined in a consistent, standardized manner. The transmission cost, output, and variable data in FERC Form 1s must be maintained in accordance with the Uniform System of Accounts.[13]

PSE contacted nine Canadian transmission utilities and asked if they would be willing to participate in the benchmarking study. Participation in the study would have required that the utilities give PSE the type of cost information that was used in this report. None of the utilities wished to participate.

Due to the absence of publicly available Canadian data, unwillingness of utilities to participate voluntarily, and non-uniformity of cost categories in Canada even if the data were available, PSE does not use Canadian utilities in its dataset, other than Hydro One.

3.1.3 The PSE Dataset

The benchmarking sample includes 57 unique utilities with annual data from 2004 to 2016. The data begins in 2004. This is the first year that transmission peak demand is reported from SNL Energy's FERC Form 1 database. The total number of observations in the dataset is 732 (here an

[13] See, e.g., *Uniform System of Accounts*, at https://www.ferc.gov/enforcement/acct-matts/usofa.asp

"observation" means one utility's costs over one year, with the variable data for that year). For some utilities, certain individual years did not yield usable observations, due to incomplete or missing data. For this reason, PSE used an "unbalanced" panel dataset to include more utilities in the benchmarking sample. The number of observations is more than sufficient for the creation of a statistically robust total cost econometric model.

The list of utilities included in the benchmarking sample is provided in the following table.

Table 4 List of Utilities in Benchmarking Sample

List of Utilities in Benchmarking Sample

Company	Most Recent Peak Demand (MW)	Company	Most Recent Peak Demand (MW)
Alabama Power Company	35,600	Kansas Gas and Electric Company	2,604
ALLETE (Minnesota Power)	1,520	Kentucky Utilities Company	5,370
Arizona Public Service Company	7,906	Louisville Gas and Electric Company	2,989
Atlantic City Electric Company	2,673	Mississippi Power Company	35,600
Avista Corporation	2,310	Monongahela Power Company	2,053
Baltimore Gas and Electric Company	6,601	Nevada Power Company	6,996
Black Hills Power, Inc.	977	New York State Electric & Gas Corporation	2,967
Central Hudson Gas & Electric Corporation	1,088	Niagara Mohawk Power Corporation	8,578
Central Maine Power Company	1,550	Northern States Power Company - MN	10,357
Cleco Power LLC	3,509	Oklahoma Gas and Electric Company	6,649
Commonwealth Edison Company	21,175	Orange and Rockland Utilities, Inc.	1,435
Connecticut Light and Power Company	6,087	PacifiCorp	18,583
Consolidated Edison Company of New York, Inc.	12,663	PECO Energy Company	8,364
Delmarva Power & Light Company	4,114	Potomac Electric Power Company	5,786
Duke Energy Carolinas, LLC	23,622	PPL Electric Utilities Corporation	7,216
Duke Energy Florida, LLC	12,082	Public Service Company of Colorado	7,604
Duke Energy Indiana, LLC	7,282	Public Service Company of New Hampshire	2,366
Duke Energy Ohio, Inc.	5,308	Public Service Electric and Gas Company	9,800
Duke Energy Progress, LLC	14,355	Rochester Gas and Electric Corporation	1,601
Duquesne Light Company	2,826	San Diego Gas & Electric Co.	4,343
El Paso Electric Company	1,877	South Carolina Electric & Gas Co.	5,266
Empire District Electric Company	1,114	Southern California Edison Company	23,687
Florida Power & Light Company	25,797	Southern Indiana Gas and Electric Company, Inc.	1,217
Gulf Power Company	35,600	Southwestern Public Service Company	6,003
Hydro One Transmission	**23,213**	Tampa Electric Company	4,453
Idaho Power Co.	4,359	Tucson Electric Power Company	4,356
Indianapolis Power & Light Company	2,670	Union Electric Company	7,768
Jersey Central Power & Light Company	5,955	West Penn Power Company	3,954
Kansas City Power & Light Company	3,714		
Sample Average Peak =	**8,518**		
Number of Utilities =	**57**		

3.1.4 The Definition of "Costs"

Both OM&A and total costs used in the benchmarking models for the U.S. transmission utilities are derived using FERC Form 1 filing data.[14] United States investor-owned utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g. distribution, transmission, generation, customer billing,

[14] All FERC data was downloaded by PSE from SNL Energy's database tool.

administrative and general). Form 1s also include information regarding "plant in service" and accumulated depreciation that is used in constructing capital costs.

PSE used a definition of "cost" for Hydro One that allowed us to achieve comparability with the definition used for the U.S. sample. The cost of transmission services purchased by U.S. utilities from other utilities is removed from the cost definition for the U.S. sample. Subtracting "transmission of electricity by others" expenses (Uniform System of Accounts category 565, on page 321 of FERC Form 1) creates a more comparable cost definition to Hydro One and, if not subtracted, would create an unfair advantage to Hydro One, since certain U.S. utilities would have inflated expenses without commensurate output values. PSE also subtracted pensions and benefit expenses from the cost definition. Given the different healthcare structures between Canada and the U.S., this expense category could slightly inflate U.S. costs relative to Hydro One.

The transmission cost definition also includes an allocated amount of administrative and general (A&G) expenses (see page 323 of FERC Form 1).[15] Some of the U.S. utilities own and operate power plants and/or conduct distribution functions. We allocated A&G expenses for those utilities based on the ratio of transmission expenses (minus transmission of electricity by others) to the total expenses of the utility minus the expenses of fuel, purchased power, transmission of electricity by others, and A&G expenses. Similarly, general capital costs are allocated for the U.S. sample by the ratio of transmission gross plant in service to total plant in service minus general and intangible plant in service.

3.2 Variables in the Benchmarking Model

In general, there are two types of variables used in econometric cost benchmarking: output variables and business condition variables. Output variables measure the output of the utility in question (i.e. what the utility "produces"). Business condition variables quantify the factors that drive costs in a particular service territory, such as terrain, input prices, and average voltage of transmission line. Variables such as "average voltage of transmission line" are business condition variables because they are, in large part, not up to the utility—service territory and electricity demand concentration (among other factors) dictate what transmission voltages are needed.

The output variables used in the total cost econometric benchmarking research are:

- Total kilometres of transmission line, and
- Maximum peak demand.

The business condition variables used in the total cost econometric benchmarking research are:

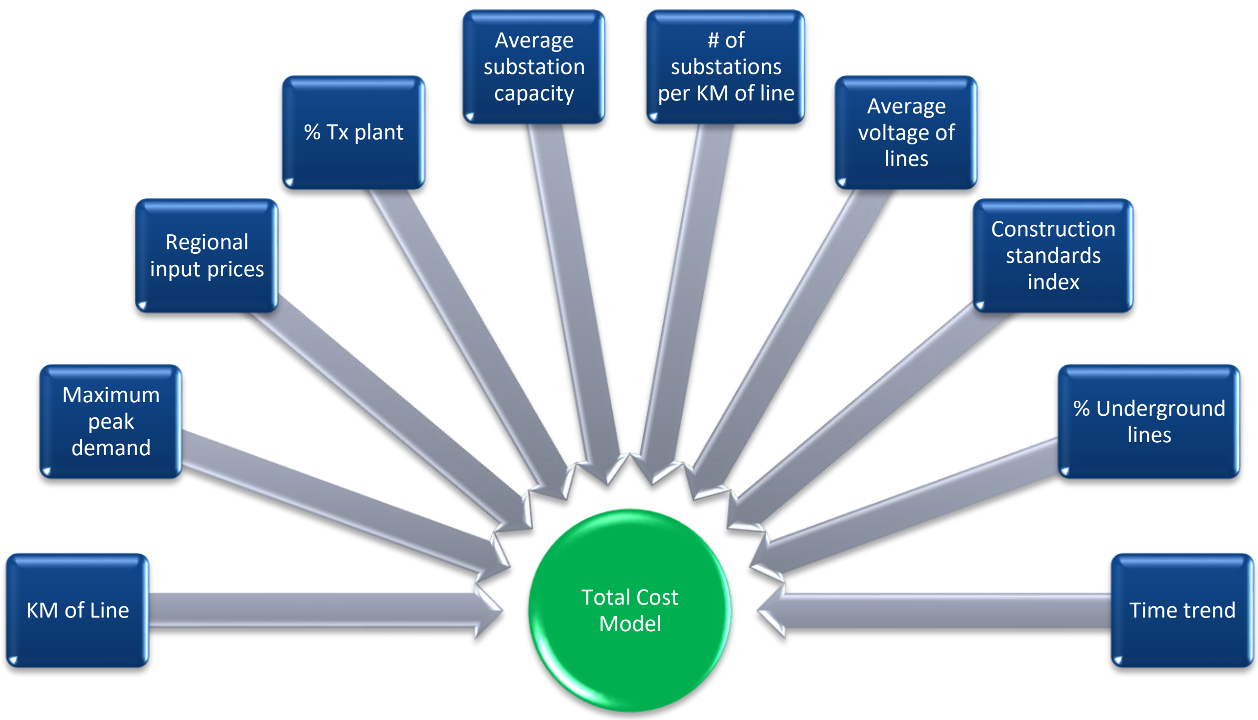
- Regional input prices (total costs in the model are divided by the input price index),
- Percent of transmission plant in total electric utility plant,

[15] The A&G expenses are after pensions and benefits expenses are subtracted.

- Average capacity in MVa per transmission substation,
- Number of transmission substations per kilometre of transmission line,
- Average voltage of transmission lines,
- Construction standards index for building a transmission pole,
- Percent of lines that are underground, and
- A time trend variable.

The variables included in the benchmark analysis are shown in the figure below.

Figure 4 Variables in Econometric Cost Model



The list of variables incorporated into the econometric model is extensive. These variables provide a robust accounting of the varying service territory conditions faced by transmission utilities. All variables are statistically significant at a 99% confidence level, and all variables are correctly signed (i.e. they are signed the way we would expect).

3.2.1 Output Variables

The total cost model includes two **output variables**. The first is the total kilometres of transmission line, the second is the maximum peak demand for each utility during the sample period. The output variables are gathered from SNL Energy's database. The raw data was gathered by SNL Energy from FERC Form 1 filings. The historical output data for Hydro One comes directly from the company. The maximum peak demand variable is calculated based on taking the maximum annual peak demand on the system in the sample that has occurred up to that year. For example, for the 2005 observation, the variable is the highest annual peak demand for either 2004 or 2005. For the 2016 observation, the maximum peak demand is the highest annual peak that has occurred since 2004.

3.2.2 Input Prices

Input prices are divided into two categories: capital and OM&A. The capital input price calculation (using the perpetual inventory capital cost method) is discussed in detail in Section 3.3 The OM&A input price captures the regional market price level that each sampled company encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price: labour and non-labour.

The labour component is calculated by taking wage levels for numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics (BLS) estimates of job occupation weights in the *Electric Power Generation, Transmission, and Distribution Industry*. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. For Hydro One, we gathered job occupation wage estimates from the 2011 Canadian census, using wage data for Ontario, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates. This provides consistency for the U.S. and Hydro One regarding labour input prices, and also puts the input price in terms of each country's currency.

The non-labour component of the OM&A input price uses the gross domestic product price index (US GDP-PI) for the U.S. utilities. The Ontario non-labour component uses the same US GDP-PI for each year, but adjusts for the purchasing power parity (PPP) index. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price, we weighted each index using a 38% labour and a 62% non-labour rate.[16] This was derived from the inflation factor research that examined the labour and non-labour components in transmission total costs. Using the capital and OM&A cost shares, PSE calculated a total input price index.

Total cost is divided by this comprehensive input price to adjust for regional input price differences between utilities and to account for annual inflation. Dividing total cost by the input price index imposes the requirement that total costs display linear homogeneity with respect to input prices. That is, as the prices of inputs increase by X%, total cost should increase by that same percentage. For example, if all of a utility's purchases (including labour) increase by 10%, its costs would also

[16] Note: this weighting is a different weighting than the one described in Section 1.1.3 and Section 2.2.1. The weighting in this section (38% labour/62% non-labour) applies to OM&A costs, which are more labor-intensive and have a larger labour component. The weighting recommended in previous sections (14% labour/86% non-labour) applies to **total** costs.

increase by 10%. This is derived from production theory, which states that costs equal input quantity multiplied by input price.

3.2.3 Business Condition Variables: Other

Beyond the two output variables and the input price index, there are six additional business condition variables included in the model (plus a time trend). Each variable is discussed briefly below.

The **percentage of transmission plant in total electric plant** uses gross plant in service information from FERC Form 1s.[17] The variable measures the ability for a transmission utility to reduce costs through economies of scope: if the utility is also a generation and/or distribution utility, there may be cost savings to the transmission utility because of this added scope. The coefficient on the variable is expected to be positive: the higher the percentage of transmission plant in total electric plant, the higher we would expect total costs to be.

The **average substation capacity** variable is measured in MVa. The variable measures the average capacity per transmission substation reported on each utility's FERC Form 1 for each year. For Hydro One the assets were reported directly to PSE. We would expect that costs would increase as the average capacity per substation increases.

The **number of transmission substations per KM of transmission line** is based on FERC Form 1 data reported each year for the U.S. sample and based on asset information reported to PSE by Hydro One. We would expect a positive correlation between: (1) the number of transmission substations per KM of transmission line, and (2) total costs.

The **average voltage of transmission lines** measures the differences in voltage levels across transmission systems. This variable is constructed by calculating a weighted average by length of the different voltage levels found on each utility's transmission system. Serving higher voltages will be more costly than serving lower voltages, *ceteris paribus*. Therefore, we would expect a positive coefficient.

The **construction standards index (or loading)** variable measures the minimum requirements for strength of transmission structures, which vary by geographic region. Transmission lines constructed in different regions must withstand different combinations of ice and wind due to local weather. A line designed for harsher loading conditions is more expensive to construct because it may require higher class poles, greater set depth, specialized insulators, and/or stronger hardware.

[17] All FERC Form 1 data was gathered by PSE using SNL Energy's Excel extraction tool. The exception is the data on pages 422 to 427 of the FERC Form 1s. This data includes all data dealing with substations and details of the transmission lines. PSE gathered and processed this data manually because SNL does not provide the details necessary for variable construction.

The loading variable is a way to quantify the expense associated with transmission line construction based on local weather conditions. This is accomplished by evaluating the percentage of strength capacity utilized under required load cases for a base transmission structure in different regions. The process and reasoning behind this variable are included in Appendix A. We would expect that a higher minimum construction requirement for a utility would result in higher total costs.

The **percentage of underground lines** measures the percentage of underground transmission lines to total transmission lines. Constructing underground transmission lines is far more costly than constructing overhead transmission lines. As the percentage of underground lines increases, we would expect total costs to increase: i.e., we expect a positive correlation between the percentage of underground lines and total costs.

The **time trend** variable captures a general industry total cost level trend over the studied period. The time trend could reflect industry trends or influences that are not captured by the current variables (or perhaps not even captured by any possible variables). Time trend variables are often found in translog cost functions and econometric total cost benchmarking research. A similar variable was included in the 4GIR benchmarking models. In the present study, the variable is calculated by taking the current year of the observation and subtracting 2,003. For observations in the year 2004, the time trend variable equals 1. In 2014, the variable equals 11 (2,014 – 2,003). The coefficient value shows how adding an additional year increases or decreases total costs. If the industry is experiencing positive productivity trends during the sample period, the coefficient value will likely be negative. That is, as each year passes we expect real costs to be decreasing, assuming all other variables remain constant. If productivity is negative, we would expect a positive coefficient sign.

3.2.4 Projected Variable Values for Hydro One

For the years 2018-2022, projected values were used for Hydro One's variables.[18]

Input prices are calculated using the same procedures as the historical data, but with inflation projections for 2018-2022.[19] Input prices are divided into two categories: capital and OM&A. There are two components used to construct the OM&A input price: labour and non-labour. The non-labour OM&A component is based on the Conference Board of Canada's projections for the GDP-IPI. The projections range from 1.8% in 2018 to 1.9% in 2022. The labour component uses the Conference Board of Canada's projections for average weekly earnings in Ontario. This ranges

[18] Hydro One 2017 actual capital and OM&A costs were available and used for the study. The asset information on substations, lines, transformers, and voltages use 2017 projections as the actuals were not yet available at the completion of the research.

[19] Input price data for 2017 was available and used in the 2017 observation for Hydro One.

from 3.1% in 2018 to 2.3% in 2022. The capital category is set to increase using the Conference Board of Canada's projections for engineering structures, electric power generation, transmission, and distribution. This ranges from 2.3% in 2018 to 2.2% in 2022.

The plant additions for 2018-2022 are based on Hydro One projections. OM&A cost projections are set based on Hydro One projections for 2019, and then escalate by 1.98% per year from the 2019 value. This 1.98% figure is based on the inflation factor recommended weighting of 14% (labour) and 86% (non-labour) using the Conference Board of Canada's projections for Average Weekly Earnings in Ontario (labour component) and their GDP-IPI projections (non-labour component) minus the X factor and stretch factor, which are set at 0.0% each. See Section 2.2.1 for how the 14%/86% weights were determined.

The **percentage of transmission plant in total electric plant** projections are based on the historic variable value for Hydro One.

The **average substation capacity** projections are based on asset projections provided to PSE by Hydro One.

The **number of transmission substations per KM of transmission line** projections are based on asset projections provided to PSE by Hydro One.

The projections for **average voltage of transmission lines** are based on asset projections provided to PSE by Hydro One.

The projections for **percentage of underground lines** are based on asset projections provided to PSE by Hydro One.

The **construction standards index** variable is set to the same value throughout all historical and projected years for Hydro One.

3.3 Perpetual Inventory Capital Cost Method

This report evaluates Hydro One's capital costs as a component of the total cost definition. PSE's measure of capital cost is based on a service price approach. This approach has a solid basis in economic theory, and is the same method used in the 4GIR research and PSE's research in Hydro One's distribution CIR application.[20] It allows for a clear-cut and standardized way to account for differences between utilities with respect to historical plant additions. The service price approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry.

[20] See Hall and Jorgensen (1967) for a discussion of the use of service price methods for measuring capital cost.

Based on this approach, the cost of capital in each period *t* is the product of indexes of the capital service price and capital quantity in place at the end of the prior period. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

Here, in each period *t*, CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value at the start of the period.

The capital quantity index is constructed using data on the value of net transmission utility plant in a benchmark year, and on gross transmission plant additions in subsequent years. It also uses an assumption about service lives. We use 1989 as the benchmark year in the current study for all U.S. utilities. We use 2002 as the benchmark year for Hydro One. This is the first feasible year to use for Hydro One, due to lack of data availability in years prior to 2002.

Hydro One provided PSE with their net transmission plant and their transmission plant additions. These included an allocation for general plant. For the U.S. sample, PSE allocated a portion of net plant and general plant additions based on the ratio of transmission gross plant in service to total gross plant in service minus general and intangible plant.

Based on the benchmark year, a "triangulated weighted average" ("TWA") is used to calculate the capital stock in 1989 or 2002. Subsequent years use the previous year's capital stock and escalate it by plant additions minus depreciation. This method is used both for Hydro One and the U.S. utilities. The formulas for the capital quantity index in 2002 and in subsequent years are provided below.[21]

$$XK^i_{2002} = \frac{Net\ Plant^i_{2002}}{TWA^i_{2002}}$$

$$XK^i_t = XK^i_{t-1} * d + \frac{Add^i_t}{WKA^i_t}$$

Under the service price approach employed in this study, capital cost has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset.

[21] For the U.S. utilities the formulas begin in 1989.

Setting the same rate of return for all transmission utilities provides consistency in determining the capital costs, so that decisions by regulators do not enter the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. We use the value of 3.59% for this parameter, based on Hydro One's 2015 Depreciation Rate Study and the U.S. Bureau of Economic Analysis (BEA) declining balance rate of 1.65 for electrical transmission, distribution, and industrial apparatus.

The variable that the capital service price components have in common is WKA_t. This is an index of the price of capital assets used in power transmission. We compute this index using data on differences in the cost of constructing utility plants between regions, and within regions over time. In particular for U.S. transmitters, we use the Handy-Whitman indexes for total power transmission plants, which vary over time and across six geographic regions. For Hydro One, we used the Handy-Whitman index for the North Atlantic region and adjusted for the Canadian PPP.

We determined the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans' *Heavy Construction Cost Data*. These indexes measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are: raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution. The level of the asset price index for each utility is the simple average of the RSMeans index values for cities in the service territory. This same source is used for both U.S. and Hydro One. The index is already adjusted for currency differences between the two countries.

3.4 Translog Cost Function

Section 3.2 above listed the variables used to benchmark transmission costs. These variables were all evaluated to quantify their effect on transmission costs. As a starting point for evaluating variables, we assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers" (i.e., the variables), can be quantified and captured by a statistical function. This function, called a "cost function," allows PSE to specify cost as a dependent variable that can be explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

A note on terminology: We use the term "estimated" to refer to the process by which the cost function is created. As the term "estimated" implies, the resultant model is not an exact function that describes every single possible variable/output and their effect on cost with 100% certainty. Some variables will remain unknown, and some variables could have associated data that is not practically available; furthermore, even a "true" model, if such a thing exists, would have an error term that reflects random variation. Thus when we "estimate" a model, it reflects the mathematical relationship between cost and cost drivers/outputs; this relationship is based on the dataset used, the variables and outputs used, the definition of "cost," and the specified procedure and assumptions for creating the model.

In general, cost is assumed to be a function of input prices, the output produced by the firm, and other independent variables that affect cost but are outside management's control. While a function specified in this manner can capture a reasonable level of cost variability, it does not explain all the elements that affect cost. Therefore, the function includes a random noise term to account for such idiosyncratic factors.

The following equation provides an example of a simple cost function:

$$C = (\beta_o * V_0) + (\beta_1 * Y) + \varepsilon$$

In this equation, the terms C and Y, denote cost and output, respectively. The beta (β) terms denote model parameters that capture the magnitude and sign of the effect of the explanatory variables on cost. For example, the variable V_0 is multiplied by its associated parameter β_0, which indicates the magnitude of the effect of V_0 on cost. Each explanatory variable will have an associated β magnitude. The error term ε captures random noise. The error term is assumed to be independent of the explanatory variables.

The data used to estimate this cost relationship can consist of different types of observations, as follows:

- Data from a single utility with multiple time observations (time series data),
- Data from many utilities observed at a single time period (cross-sectional data), or
- Data from many utilities with multiple time observations (cross-sectional time-series or panel data).

The procedure used to estimate model parameters is affected by the type of data used to determine the model. In our present study, we have a panel dataset with cost data from multiple utilities.

3.4.1 Statistical Tests

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. In particular, standard errors of parameter estimates, which measure the precision with which a parameter is estimated, are used to construct a test of a relevant hypothesis. The hypothesis to be tested is "the explanatory variable in question has no statistically significant effect on cost". This procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90 percent confidence threshold in our research.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately used to assess the cost performance of each firm in the sample. By "plausibly signed" we mean that its sign (positive/negative) accords with our intuitive understanding of the relationship between that parameter and the variable. For example, we would "expect" to see costs rise as the maximum peak demand served increases (i.e. the maximum peak demand parameter would be positively signed).

A cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark reflects the performance of an average utility facing the business conditions of the utility whose values are used to generate the benchmark.

If a given utility's actual cost is below the benchmark cost, its cost performance is better than average—it spent less than did an average hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, its cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is statistically significantly different from average.

3.4.2 Model Specification

In multivariate regression analysis, the constructed model is designed to use a set of independent (often called explanatory or right-hand-side) variables to "explain" movement in the dependent (often called the left-hand-side) variable. The numerical relationship between an independent variable and the dependent variable is provided through an estimated coefficient value. Under the assumptions of the model, this coefficient value is considered an unbiased estimator of the relationship. Multivariate regression analysis also makes statements about the precision of each coefficient value. Precision in this context is a statement about how confident or statistically valid the coefficient value is. When all the assumptions of multivariate regression are satisfied, the coefficient values are the best (or most precise) unbiased estimators that are available.

Two common issues arise in multivariate regression using real world data: heteroscedasticity and autocorrelation. Neither of these issues cause the coefficient values to be biased. This is important because it means the researcher does not need to worry about correcting the coefficient values: they are not misleading. However, both conditions render the statements about precision problematic. Specifically, the problem with heteroscedasticity and autocorrelation is that they increase the regression variance calculations, which means the researcher is less confident in the calculated coefficient values. For decades, the standard correction procedure involved trying to figure out the nature of each problem and strategically weighting the regression to render heteroscedasticity and autocorrelation less of a problem. One key issue with this strategy is that the researcher may have a hard time truly understanding how to reweight the regression. Additionally, the coefficient values will be different after the reweighting.

More recent treatments for dealing with heteroscedasticity and autocorrelation focus the correction procedures on methods that do not alter the regression or the coefficient values. Instead of reweighting the regression itself, these strategies leave the regression unaltered and focus on altering the way the variances of the coefficients are calculated. These procedures are systematic and do not depend on understanding the underlying reason for the heteroscedasticity and autocorrelation.

For our analysis, we have chosen to estimate the precision of our coefficients using Driscoll-Kraay standard errors.[22] Driscoll-Kraay standard errors have been coded and available in the STATA software suite since 2007.[23] The computer software calculates information crucial to understanding whether each relationship as described by each coefficient can be supported statistically. These statistical claims are usually reported as either t-ratios or probability values.[24]

3.5 Total Cost Econometric Model

The econometric model parameter estimates along with t-statistics are provided in the table below. All first-order variables exceed the standard threshold of a significance level of 90% (t-stat greater than 1.645). In fact, all variables exceed a 99% statistical significance threshold (t-stat greater than 2.567). The adjusted R-squared value of the model is 0.900. All variables are correctly signed according to a priori engineering theory.

[22] Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[23] Hoechle, Daniel, 2007 "Robust standard errors for panel regressions with cross-sectional dependence," *The Stata Journal* 7(3): 281-312.

[24] See Wooldridge, J. *Introductory Econometrics, 4th Edition*, pp. 122.

Table 5 Econometric Model Parameter Estimates

Total Cost Model Estimates

VARIABLE KEY

KM = Total transmission Kilometres of line
D = Maximum peak demand
Tx = Percent of transmission plant in total electric utility plant
Cap = Average capacity (MVa) per substation
Sub = Number of transmission substations per KM of line
Volt = Average voltage of transmission lines
CS = Construction standards of building transmission pole
UG = Percent of transmission lines underground
Trend = Time trend (current year minus 2003)

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
KM	0.676	42.770	CS	0.206	7.140
KM*KM	-0.172	-7.910			
KM*D	0.483	7.190	UG	3.198	11.560
D	0.237	22.970	Trend	0.013	10.810
D*D	-0.259	-7.970			
			Constant	10.210	122.620
Tx	0.478	11.600			
			Adjusted R-Squared	0.899	
Cap	0.236	11.400			
			Sample Period:		2004-2022
Sub	0.191	16.660	Number of Observations		732
Volt	0.474	27.080			

4 TFP Index Methodology

In the context of electric utilities, productivity is the quantity of output produced by the utility divided by the input quantity expended by the utility. The output quantity index measures the level of output provided by the utility. The input quantity index measures the level of resources used. PSE uses indexing techniques to capture outputs and inputs, which are in turn used to create a productivity term. We then examine how this productivity ratio changes over time to determine the productivity index trend.

The input quantity index consists of economic resources, such as OM&A labour, OM&A materials, and capital stock. The output quantity index in this study includes: (1) kilometers of transmission lines, and (2) maximum peak demand. These two outputs are combined into one output index using cost elasticity weights derived from the total cost econometric model.

The TFP trend is the difference between the annual growth rate in the output quantity index and the input quantity index.

$$\boldsymbol{TFP\ trend = Output\ Quantity\ trend - Input\ Quantity\ trend}$$

TFP trend measurement differs from total cost benchmarking; in the latter, utilities are compared relative to the average efficiency level of other utilities within the industry. TFP measures how productivity is changing over time for that same industry or utility. TFP does not, however, provide a comparative efficiency assessment to other utilities within the industry, because we have no context for the relative efficiency level of the individual utilities. However, TFP research, when combined with total cost benchmarking (as is the case in this report), can provide that context.

4.1 TFP Sample

The sample period for the TFP research begins in 2004 and ends in 2016. We also provided projected TFP results for Hydro One through 2022. 2004 is the first viable year to begin the study, given the availability of peak demand values for the sample.

There are 48 utilities that comprise the TFP sample. The following table provides the list of utilities included in the TFP sample. This list is smaller than the one for the total cost benchmarking sample, because for the TFP analysis, utilities needed an observation in every single year of the sample period. In other words, we needed a balanced panel—we could not use any utility that had missing data in any one of the years 2004-2016. This contrasts with the benchmarking model, where a specific year for a specific utility can be omitted if that data is unavailable (while still using other years for that utility), resulting in an unbalanced panel estimation.

Table 6 Utilities in TFP Sample

List of Utilities in TFP Sample

Company	Most Recent Peak Demand (MW)	Company	Most Recent Peak Demand (MW)
Alabama Power Company	35,600	Kentucky Utilities Company	5,370
ALLETE (Minnesota Power)	1,520	Louisville Gas and Electric Company	2,989
Arizona Public Service Company	7,906	Mississippi Power Company	35,600
Avista Corporation	2,310	Monongahela Power Company	2,053
Black Hills Power, Inc.	977	Nevada Power Company	6,996
Central Hudson Gas & Electric Corporation	1,088	New York State Electric & Gas Corporation	2,967
Cleco Power LLC	3,509	Northern States Power Company - MN	10,357
Commonwealth Edison Company	21,175	Oklahoma Gas and Electric Company	6,649
Connecticut Light and Power Company	6,087	PacifiCorp	18,583
Consolidated Edison Company of New York, Inc.	12,663	PECO Energy Company	8,364
Duke Energy Carolinas, LLC	23,622	Potomac Electric Power Company	5,786
Duke Energy Indiana, LLC	7,282	PPL Electric Utilities Corporation	7,216
Duke Energy Ohio, Inc.	5,308	Public Service Company of Colorado	7,604
Duke Energy Progress, LLC	14,355	Public Service Company of New Hampshire	2,366
Duquesne Light Company	2,826	Rochester Gas and Electric Corporation	1,601
El Paso Electric Company	1,877	San Diego Gas & Electric Co.	4,343
Empire District Electric Company	1,114	South Carolina Electric & Gas Co.	5,266
Florida Power & Light Company	25,797	Southern California Edison Company	23,687
Gulf Power Company	35,600	Southern Indiana Gas and Electric Company, Inc.	1,217
Hydro One Transmission	**23,213**	Southwestern Public Service Company	6,003
Idaho Power Co.	4,359	Tampa Electric Company	4,453
Indianapolis Power & Light Company	2,670	Tucson Electric Power Company	4,356
Kansas City Power & Light Company	3,714	Union Electric Company	7,768
Kansas Gas and Electric Company	2,604	West Penn Power Company	3,954
Sample Average Peak =	**9,015**		
Number of Utilities =	**48**		

4.2 Output Quantity Index

This section describes the TFP output quantity index calculations. PSE used the same definition of outputs for the TFP study as we did for the econometric total cost benchmarking study. There are two outputs: kilometers of transmission lines and maximum peak demand.

The two outputs need to be combined into one output quantity index. PSE accomplished this using output weights derived from the econometric total cost model. The weights are 73.9% and 26.1% for KM of line and maximum peak demand, respectively.

These two outputs are crucial components of transmission outputs. The main function of a transmission grid is to connect power supply with electric demand via distribution networks. The length of lines are constructed to connect generation with these distribution networks. Transmission systems are constructed not only to connect generation with distribution, but also to meet the electric demands of the end-use consumers. Systems are constructed to meet the maximum peak demands of these consumers.

4.2.1 Output Quantity Index Results

The two components of the output quantity index for the industry and Hydro One are provided in the following tables. After combining the components, the overall index is provided in the last column. The industry KM of line has grown by 0.50% per year over the full sample period. The industry's maximum peak demand grew at an annual rate of 1.34% over the full sample period. However, much of this growth was prior to 2009. Since 2010, the industry's maximum peak demand has only increased by 0.21% per year.[25] The overall output index grew by 0.72% per year during the full sample period, and by 0.48% per year since 2010.

Hydro One's outputs have grown at a considerably slower rate than those of the U.S. electric transmission industry. The company's KM of line and maximum peak demand have increased by 0.14% and 0.51% per year from 2004 to 2016, respectively. Hydro One's output quantity index grew by an average annual rate of 0.23% from 2004 to 2016. During the period of 2019 to 2022, both outputs are projected to essentially remain constant. We note that the maximum peak demand variable has been constant for Hydro One since 2006. The value is 27,005 MW. This is because all reported Hydro One peak demands subsequent to 2006 have been below 27,005 MW.

[25] Given the definition of the maximum peak demand variable, the growth rate has a floor of zero.

Table 7 Outputs for the U.S. Industry (Sum of Industry)

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	273,805	419,411	1.000
2005	274,488	440,860	1.015
2006	275,515	453,768	1.025
2007	277,790	466,952	1.039
2008	279,082	479,711	1.050
2009	279,630	481,862	1.053
2010	280,768	486,122	1.059
2011	282,245	488,092	1.064
2012	285,787	488,247	1.074
2013	286,423	488,658	1.076
2014	289,011	490,007	1.084
2015	291,246	492,091	1.091
2016	290,637	492,357	1.090
Average Annual Growth Rate			
2004-2016	0.50%	1.34%	0.72%
2010-2016	0.58%	0.21%	0.48%

Table 8 Outputs for Hydro One

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	20,603	25,414	1.000
2005	20,547	26,160	1.006
2006	20,625	27,005	1.017
2007	20,624	27,005	1.017
2008	20,661	27,005	1.018
2009	20,658	27,005	1.018
2010	20,676	27,005	1.019
2011	20,694	27,005	1.019
2012	20,891	27,005	1.026
2013	20,904	27,005	1.027
2014	20,882	27,005	1.026
2015	20,948	27,005	1.029
2016	20,949	27,005	1.029
2017 (projected)	20,689	27,005	1.019
2018 (projected)	20,965	27,005	1.029
2019 (projected)	20,967	27,005	1.029
2020 (projected)	20,967	27,005	1.029
2021 (projected)	20,970	27,005	1.029
2022 (projected)	20,974	27,005	1.029
Average Annual Growth Rate			
2004-2016	0.14%	0.51%	0.23%
2010-2016	0.22%	0.00%	0.16%
2004-2018	0.12%	0.43%	0.21%
2019-2022	0.01%	0.00%	0.01%

4.3 Input Quantity Index

There are two components to the input quantity index: OM&A quantity and capital quantity. These two measures are then combined using Tornqvist indexes based on using the cost shares of each input component. Tornqvist indexes are a commonly used indexing methodology, and this is the same approach used in the 4GIR TFP research.

4.3.1 OM&A Quantity

The OM&A quantity used in the TFP calculation is derived by dividing annual OM&A expenses in year *t* by the OM&A input price index in year *t*.

$$OM\&A\ Quantity_t = \frac{OM\&A\ Expenses_t}{Input\ Price\ Index_t}$$

4.3.2 OM&A Cost and Input Price Definitions

PSE used the same cost and price definitions for both the TFP and the benchmarking research. Please see Section 3.1.4 and 3.2 for a description of both.

4.3.3 Capital Quantity: Perpetual Inventory Capital Method

PSE used the same procedures in both the benchmarking and productivity research for the capital quantity index. For a discussion on the capital quantity calculations, please see Section 3.3

4.3.4 Input Quantity Index Results

The input quantity index is provided in the tables following. The first table shows the industry capital quantity index, OM&A index, and then the combined input quantity index from 2004 to 2016. The second table shows the same results for Hydro One from 2004 to 2022. The industry's input quantities grew at a rapid pace over 2004 to 2016. This was especially true for the capital quantity index, which grew at an average annual rate of 2.65%. The OM&A quantity for the industry grew at a rate of 1.55% from 2004 to 2016.

The overall input quantity index for the industry grew at an annual rate of 2.43% from 2004 to 2016. This rate has accelerated since 2010, due to a ramp up in the capital quantity trend.

Hydro One's input quantities have grown at a much slower rate. This is the reason for Hydro One's higher productivity trend relative to the industry. Hydro One's capital quantity grew by 0.81% per year from 2004 to 2016, and the company's OM&A quantity declined from 2004 to 2016, with a growth rate of -0.84% per year. The overall input quantity index at Hydro One grew by 0.54% per year from 2004 to 2016. Over the period of 2019-2022, capital quantities are projected to grow by 1.68% per year, OM&A quantity is expected to grow by -0.11% per year, and the overall input quantity index is expected to grow by 1.44% per year. The growth rate in the overall input quantity index of Hydro One during the CIR period is far slower than the historical input quantity growth rates of the industry.

Table 9 Input Quantities for the U.S. Transmission Industry

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2004	863,480	2,602,459	1.000
2005	867,154	3,236,377	1.074
2006	875,863	3,088,031	1.065
2007	888,002	2,877,436	1.053
2008	907,501	2,990,118	1.081
2009	926,827	2,901,694	1.089
2010	953,150	3,045,953	1.126
2011	973,107	2,850,135	1.125
2012	1,017,711	2,859,279	1.165
2013	1,060,937	2,887,322	1.205
2014	1,110,031	2,845,530	1.244
2015	1,153,049	3,010,769	1.297
2016	1,186,544	3,135,181	1.339
Average Annual Growth Rate			
2004-2016	2.65%	1.55%	2.43%
2010-2016	3.65%	0.48%	2.88%

Table 10 Input Quantities for Hydro One

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2004	143,511	255,149	1.000
2005	142,957	235,035	0.980
2006	141,713	259,196	0.993
2007	142,133	286,368	1.017
2008	141,074	242,287	0.977
2009	142,925	279,181	1.014
2010	146,105	271,958	1.027
2011	148,148	256,352	1.028
2012	153,426	254,587	1.057
2013	154,272	263,800	1.068
2014	156,752	234,679	1.061
2015	156,570	256,616	1.076
2016	158,222	230,726	1.067
2017 (projected)	159,450	216,387	1.064
2018 (projected)	162,849	209,019	1.078
2019 (projected)	163,969	214,844	1.089
2020 (projected)	166,565	214,566	1.104
2021 (projected)	169,328	214,359	1.119
2022 (projected)	172,436	214,144	1.137
Average Annual Growth Rate			
2004-2016	0.81%	-0.84%	0.54%
2010-2016	1.33%	-2.74%	0.63%
2004-2018	0.90%	-1.42%	0.54%
2019-2022	1.68%	-0.11%	1.44%

5 Total Cost Benchmarking Results

Using a sample of 57 transmission utilities, PSE estimated a translog total cost econometric model. As required by accepted best practice, all first order variables are signed according to theory and are statistically significant at a 90% level of confidence.[26]

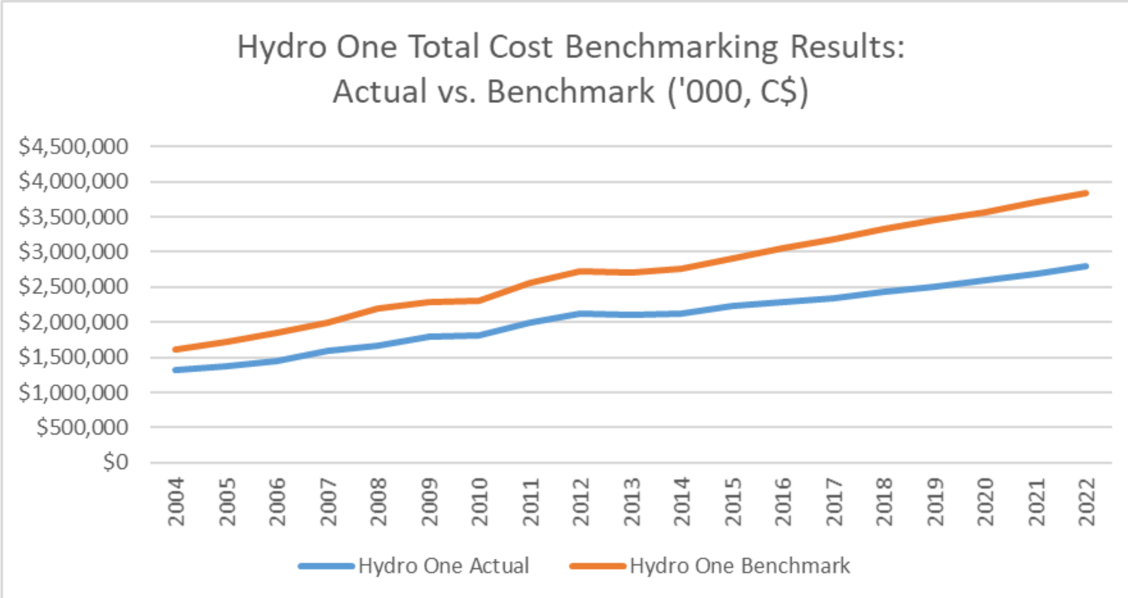
The benchmark scores are derived by calculating the logarithmic percentage between Hydro One's actual total costs and their model-predicted total costs. The model-predicted results are produced from a model that excludes Hydro One from the sample. This provides a truly external benchmark value to compare Hydro One's total costs against. A negative number implies that the company's actual costs are lower than the benchmark. The table following shows the scores for the historical and projected years.

[26] In fact, all first order variables in the model are statistically significant at the 99% confidence level.

Table 11 Hydro One's Cost Performance 2004-2022

Year	Hydro One Actual Costs (Thousands, C$)	Hydro One Benchmark Costs (Thousands, C$)	% Difference (Logarithmic)
2004	$1,321,847	$1,607,757	-19.6%
2005	$1,374,866	$1,729,615	-23.0%
2006	$1,456,209	$1,844,035	-23.6%
2007	$1,589,793	$1,996,161	-22.8%
2008	$1,672,186	$2,200,213	-27.4%
2009	$1,786,248	$2,293,710	-25.0%
2010	$1,808,049	$2,310,014	-24.5%
2011	$1,987,327	$2,568,490	-25.7%
2012	$2,115,512	$2,723,021	-25.2%
2013	$2,100,004	$2,703,669	-25.3%
2014	$2,123,453	$2,765,321	-26.4%
2015	$2,230,624	$2,908,015	-26.5%
2016	$2,283,979	$3,047,901	-28.9%
2017 (projected)	$2,338,963	$3,174,800	-30.6%
2018 (projected)	$2,430,797	$3,323,325	-31.3%
2019 (projected)	$2,511,095	$3,447,400	-31.7%
2020 (projected)	$2,600,683	$3,573,281	-31.8%
2021 (projected)	$2,695,299	$3,706,040	-31.8%
2022 (projected)	$2,797,680	$3,843,932	-31.8%
Average % Difference			
2014-2016			**-27.3%**
2019-2022			**-31.8%**

Figure 5 Hydro One's Cost Performance 2004-2022



This table and graph illustrate Hydro One's total costs have consistently been below the benchmark value since 2004. In 2016, Hydro One is over $700 million below its benchmark total costs. This difference in Hydro One's actual to benchmark costs is projected to increase to over $1,000 million by 2022. This assumes Hydro One's application is approved in full. Throughout the 2019-2022 period, Hydro One's projected total costs are approximately 31.8% below benchmark expectations.

6 Productivity Results

Productivity is defined as the ratio of an output quantity index to an input quantity index.

$$Productivity = \frac{Output\ Quantity\ Index}{Input\ Quantity\ Index}$$

The annual change in this index measures the TFP trend. The TFP trend is the difference between the annual growth rate in the output quantity index and the input quantity index.

$$\boldsymbol{TFP\ trend = Output\ Quantity\ trend - Input\ Quantity\ trend}$$

Using a sample of 48 transmission utilities, PSE calculated the TFP trend for the U.S. transmission industry from 2004 to 2016. Additionally, we calculated the TFP trend for Hydro One from 2004 to 2022.

The year over year results and average annual growth rates are provided in the table following.

Table 12 Industry and Hydro One TFP Results

Year	Industry TFP Index	Industry TFP Growth Rate	Hydro One TFP Index	Hydro One TFP Growth Rate
2004	1.000		1.000	
2005	0.945	-5.6%	1.026	2.6%
2006	0.963	1.9%	1.024	-0.2%
2007	0.987	2.5%	1.000	-2.4%
2008	0.971	-1.6%	1.042	4.1%
2009	0.967	-0.5%	1.003	-3.8%
2010	0.940	-2.8%	0.992	-1.2%
2011	0.946	0.6%	0.992	0.0%
2012	0.922	-2.6%	0.971	-2.1%
2013	0.893	-3.2%	0.962	-1.0%
2014	0.871	-2.4%	0.967	0.5%
2015	0.841	-3.5%	0.956	-1.1%
2016	0.814	-3.3%	0.964	0.8%
2017 (projected)	NA	NA	0.958	-0.6%
2018 (projected)	NA	NA	0.954	-0.4%
2019 (projected)	NA	NA	0.945	-1.0%
2020 (projected)	NA	NA	0.933	-1.3%
2021 (projected)	NA	NA	0.920	-1.4%
2022 (projected)	NA	NA	0.906	-1.6%
Average Annual Growth Rate				
2004-2016	-1.71%		-0.31%	
2010-2016	-2.40%		-0.47%	
2004-2018	NA		-0.33%	
2019-2022	NA		-1.43%	

PSE calculated the total factor productivity trend for the industry from 2004 to 2016. This twelve-year period from 2004 to 2016 showed an average annual decline in industry TFP, with an annual growth rate of -1.71%. Since 2010, the industry TFP has declined at an even higher rate, with an average annual growth rate of -2.40%.

Hydro One's own TFP from the 2004 to 2016 period declined, with an average annual growth rate of -0.31%. From 2010 to 2016, Hydro One's TFP has declined, with an average annual growth rate of -0.47%. Hydro One's TFP is projected to decrease during the period of 2019 to 2022, with an average annual growth rate of -1.43%. Despite the negative growth rate, this still outpaces the historical industry TFP (2004 to 2016) by 0.28%.

6.1 Interpretation of Negative TFP Growth

Changes in TFP will have tangible impacts on transmission utility costs and the value of electricity provided to end-use consumers. A negative industry TFP trend implies higher electricity costs for the industry (beyond inflationary cost increases). The OEB addressed this possibility in the Board's Decision dated November 21, 2013 in EB-2010-0379 (page 17):

> The Board acknowledges that achieved industry TFP may be negative due to unforeseen events and/or situations in which costs may be incurred with no corresponding increase in output.

TFP is a measure of the change in the outputs delivered by the utility (or industry) relative to the inputs required to deliver those outputs. However, it is important to note that a negative TFP growth rate does not necessarily indicate declining efficiency at either the industry or the utility level. Recall that the TFP trend equals the Output Quantity Index trend minus the Input Quantity Index trend. Negative TFP trends indicate that measured outputs are growing slower than inputs.

While declining efficiency is certainly one possibility when observing negative TFP trends, there are a number of other possibilities. Systemic possibilities include:

1. The increasing of "outputs" that are not being measured within the TFP calculation. While PSE's output measure incorporated two key outputs of a transmission utility, there are other valued utility functions that are difficult, if not impossible, to incorporate and quantify. These other valued functions could include reliability, safety, meeting increased regulatory requirements, increasing generation interconnections from wind or solar, providing enhanced environmental stewardship, and increasing other aspects of power quality.

2. External circumstances can change over time. One circumstance often found in modern western economies is slower growth. For some countries, output growth has slowed due to more energy efficient appliances and machinery, and conservation programs. This has slowed the growth in peak demands (in kW). Since the TFP trend is a function of the output index, this slower growth will tend to slow down TFP.

3. A common external circumstance that is changing across the electric industry, but is problematic to quantify, is the aging of capital infrastructure. Due to the post-World War II population boom and increasing use per customer during that time, utilities needed to heavily invest in capital infrastructure to meet the higher peak demands (unlike the current situation, in the past utilities were able to fund much of this investment through increasing billing determinants rather than higher prices). At several utilities throughout North America, a high proportion of capital infrastructure is now past its useful life and needs replacement. However, capital expenditures may need to increase to replace this older

infrastructure. Additionally, maintenance costs will also tend to increase as the grid becomes older. The capital replacement expenditures and increasing maintenance costs will tend to cause a decline in TFP.

Unfortunately, it is impossible to empirically adjust for all the underlying causes of observed TFP trends. However, TFP measures are useful indicators of performance, assuming these other considerations are kept in mind.

7 Inflation Factor Research

In the Board's September 28, 2017 Decision for Hydro One Sault Ste. Marie, LLP (Hydro One SSM) regarding the company's application for electricity transmission, the Board stated that evidence on the appropriate input weights for the inflation factor should accompany future rate applications by Hydro One SSM.[27] In the Hydro One SSM application, the company put forth the same input weights as were used for the distributors in 4GIR. The distributors' inflation factor has a 70% weight on non-labour and a 30% weight on labour. PSE was tasked with providing evidence for revising these weights to align with the electric transmission industry.

To accomplish this task, PSE started with the total cost benchmarking sample in this study. Using this sample, we gathered direct transmission salaries, administrative and general salaries, outside services employed, and electric construction salaries. We then allocated the transmission portion of the administrative and general salaries, outside services employed, and electric construction salaries and summed them with the direct transmission salaries to get a total labour cost for each observation in the benchmarking sample. We then divided this total labour cost by the total cost number in the benchmarking sample to get the labour percentage. This labour percentage was then averaged for the entire benchmarking sample.

The allocator used for administrative and general salaries and outside services employed is the same allocator as the one used in the TFP and benchmarking research to allocate all administrative and general expenses. The equation for the allocator is below.

$$Allocator^{OM\&A} = \frac{Tx\ Expenses - Tx\ of\ Electricity\ by\ Others\ Expenses}{Total\ Expenses - Fuel\ Expenses - Tx\ by\ Others - A\&G\ Expenses}$$

The allocator for the electric construction salaries is the portion of transmission plant additions for that year to total plant additions minus general plant additions. The equation is below.

$$Allocator^{capital} = \frac{Tx\ plant\ additions}{Total\ plant\ additions - General\ plant\ additions}$$

The full equation used to calculate the labour percentage in total costs is the following.

$$\frac{Tx\ Salaries + AG\ salaries * Allocator^{OM\&A} + Outside\ Services\ Employed * Allocator^{OM\&A} + Construction\ Salaries * Allocator^{Capital}}{Total\ Costs}$$

The average labour percentage for the entire benchmarking sample is 14%. The remaining costs (86%) are deemed to be non-labour costs.

[27] EB-2016-0356, Decision and Order dated September 28, 2017. Page 5.

8 PSE Recommendations

PSE used the results of this study to:

(1) Make recommendations regarding the CIR parameters that should be used in Hydro One's CIR application, and

(2) Assist the Board stakeholders in assessing the reasonableness of the cost levels contained in Hydro One's CIR application.

8.1 PSE's recommendations on CIR parameters

PSE recommends the following general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$$Growth\ Revenue = Inflation - X - Stretch + Capital\ Factor$$

The specific parameter values for each component are as follows:

- PSE recommends an inflation factor calculated using the 4GIR calculation procedures, but with weights of 14% labour and 86% non-labour instead of the 4GIR weights. In 4GIR, the inflation factor is weighted with 30% of the growth in AWE for Ontario and 70% of the growth in GDP-IPI FDD. The AWE accounts for the labour component of total costs and the GDP-IPI FDD accounts for the non-labour component. PSE's recommendation for the electric transmission industry is to calculate the inflation factor with a 14% weight on AWE and an 86% weight on GDP-IPI FDD.

- The PSE X factor recommendation is 0.0%. This is based on the negative industry TFP finding of -1.71%. While a negative X factor could be considered, the 4GIR Decision made clear the Board does not desire to have a negative X factor embedded within the escalation formula. For this reason, PSE recommends a 0.0% X factor, which is the same X factor that is found in 4GIR.

- The PSE stretch factor recommendation is 0.0%. There are two reasons for this recommendation. The first is the "implicit stretch factor" of 1.71%, which is due to the X factor being set at 0.0%. This "implicit stretch factor" is far higher than the 0.33% implicit stretch factor embedded in the 4GIR Decision. The second reason is the total cost benchmarking result that shows Hydro One will be 31.8% below its benchmark costs throughout the 2019-2022 CIR period. The 4GIR Decision would indicate a 0.0% stretch factor. PSE believes this strong cost performance warrants a 0.0% stretch factor.

- PSE recommends not including an output growth factor to simplify the revenue cap formula, since the expected growth rate is close to 0%, and due to the possible redundancy of including both an output growth factor and a capital factor.

- The capital factor is based on Hydro One's proposed capital spending needs. PSE is not making any recommendations regarding the magnitude of the capital factor. We do, however, insert the proposed capital spending amounts into the TFP and total cost benchmarking studies, so the Board and stakeholders can ascertain the projected TFP trends and total cost benchmarking scores that result from the proposed level of capital spending.

8.2 Reasonableness of Hydro One's Total Cost Levels

This study provides a total cost econometric benchmarking study and a TFP trend analysis of Hydro One's costs and productivity. These studies are conducted on both the historical outcomes and the outcomes projected by Hydro One. Both studies reveal Hydro One comparing favorably to the industry, historically and into the future.

The graph below shows Hydro One's total cost benchmarking results for the historical time period (2004-2017) and the projected time period (2018-2022).

Figure 6 Hydro One Total Cost Benchmarking Results

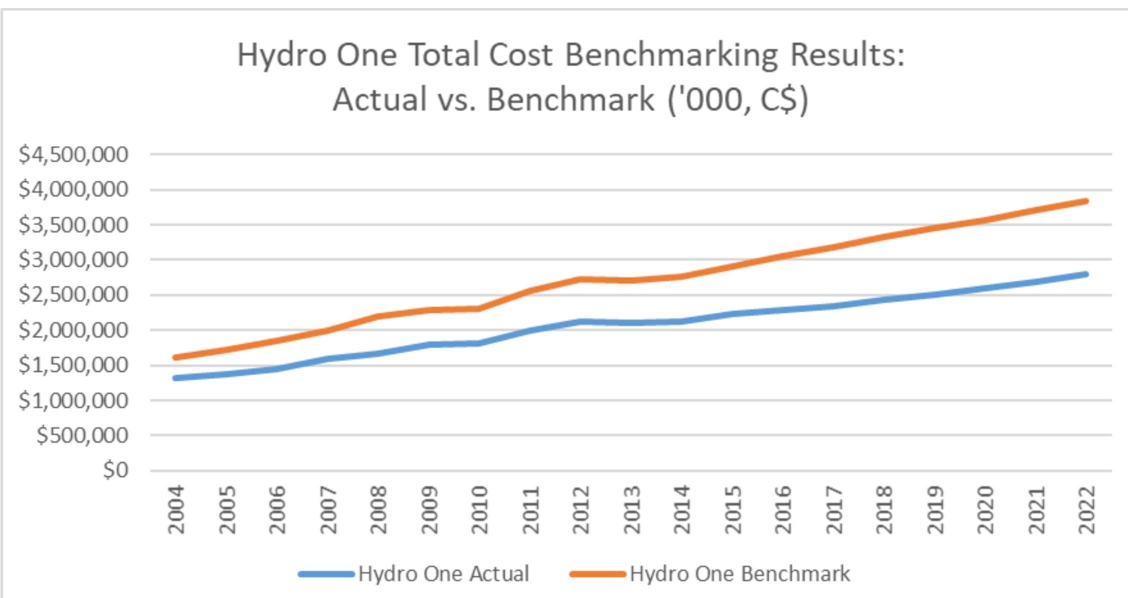
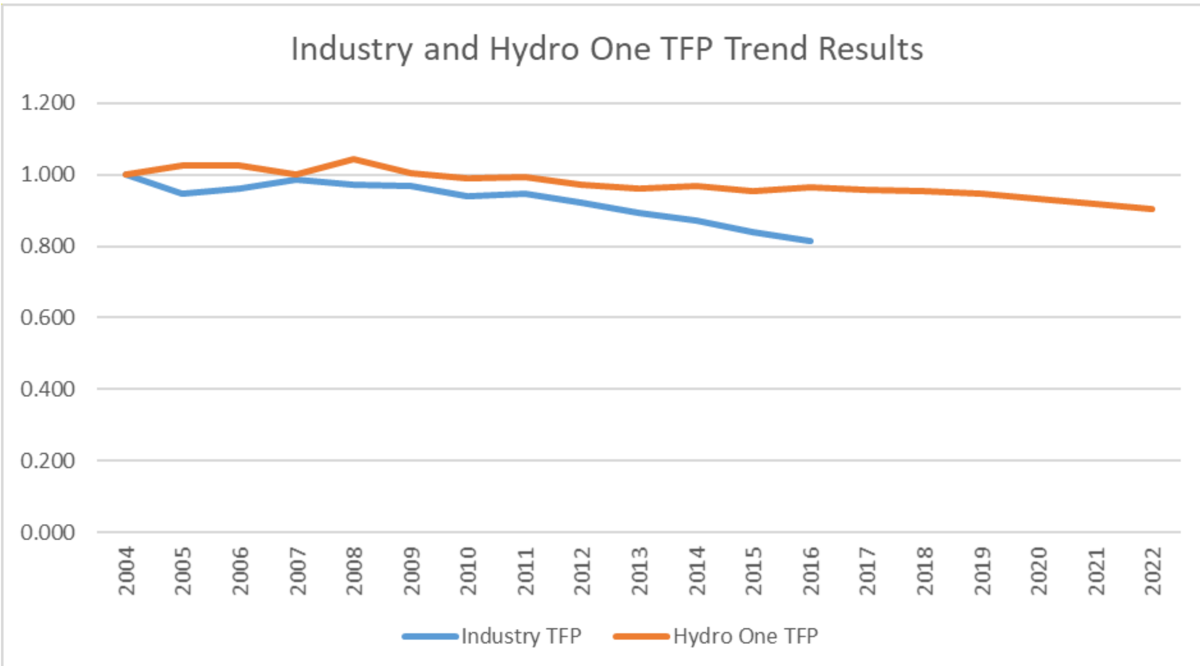


Figure 6 shows that Hydro One's total costs have consistently been below the benchmark value since 2004. In 2016, Hydro One is approximately $700 million below its benchmark total costs. This difference in Hydro One's actual to benchmark costs is projected to increase to over $1,000 million by 2022. This assumes Hydro One's application is approved in full. Throughout the 2019-

2022 period, Hydro One's projected total costs are approximately 31.8% below benchmark expectations.

Hydro One's TFP results also indicate a utility whose TFP trend is higher than the industry's. Again, this is true both historically and into the future. The following figure contrasts the industry's TFP trend with Hydro One's.

Figure 7 Industry vs. Hydro One TFP



The industry's TFP has declined by 1.71% annually over the entire 2004 to 2016 period. This trend has accelerated in recent years. Since 2010, industry TFP has declined by 2.40% annually. Hydro One's TFP trend from 2004-2016 is -0.31% per year. Hydro One's projected TFP is expected to move lower, with a decline of 1.43% per year going forward to 2022. However, this remains above the industry's past TFP trend.

9 Appendix A: Transmission Loading Variable

This Appendix explains the theory and data behind the transmission loading variable discussed in Section 3.2.3 (also known as the construction standards index). Per the Canadian Standards Association (CSA) and the National Electrical Safety Code (NESC), overhead transmission lines constructed throughout Ontario, Canada and the United States must withstand a minimum combination of accumulated ice and wind based on local extreme historical weather conditions. As a result, the required minimum design/build structural strength for an overhead transmission line is dependent on the physical location of the line.

This minimum structural strength requirement has a direct influence on the overall capital cost a utility must devote to its overhead transmission plant. For example, a transmission structure designed for harsher loading conditions is more expensive to construct because it may require larger diameter poles, greater setting or foundation depth, specialized insulators, and/or stronger hardware.

Furthermore, since these minimum strength requirements are developed from documented historical weather conditions, they provide an indirect indication of the severity of extreme ice and wind storms that overhead transmission lines are exposed to, which can influence operational and maintenance costs.

To account for the influence of CSA and NESC minimum overhead transmission line structure strength requirements and associated extreme weather conditions as they relate to total cost benchmarking, Power System Engineering's transmission line design engineers developed a related variable for statistical analysis. This was accomplished by evaluating the percentage of utilized strength capacity, under required CSA and NESC load cases, for a base transmission structure in different zones.

"Percentage of utilized strength capacity" is the percentage of the load resulting from specific design criteria (e.g., this line was designed to meet winds of X mph and ice of Y thickness) as a function of the overall maximum strength of the structure. The variable is a way to quantify the expense associated with transmission line construction based on local weather conditions. There were three main steps in developing the variable, as described below.

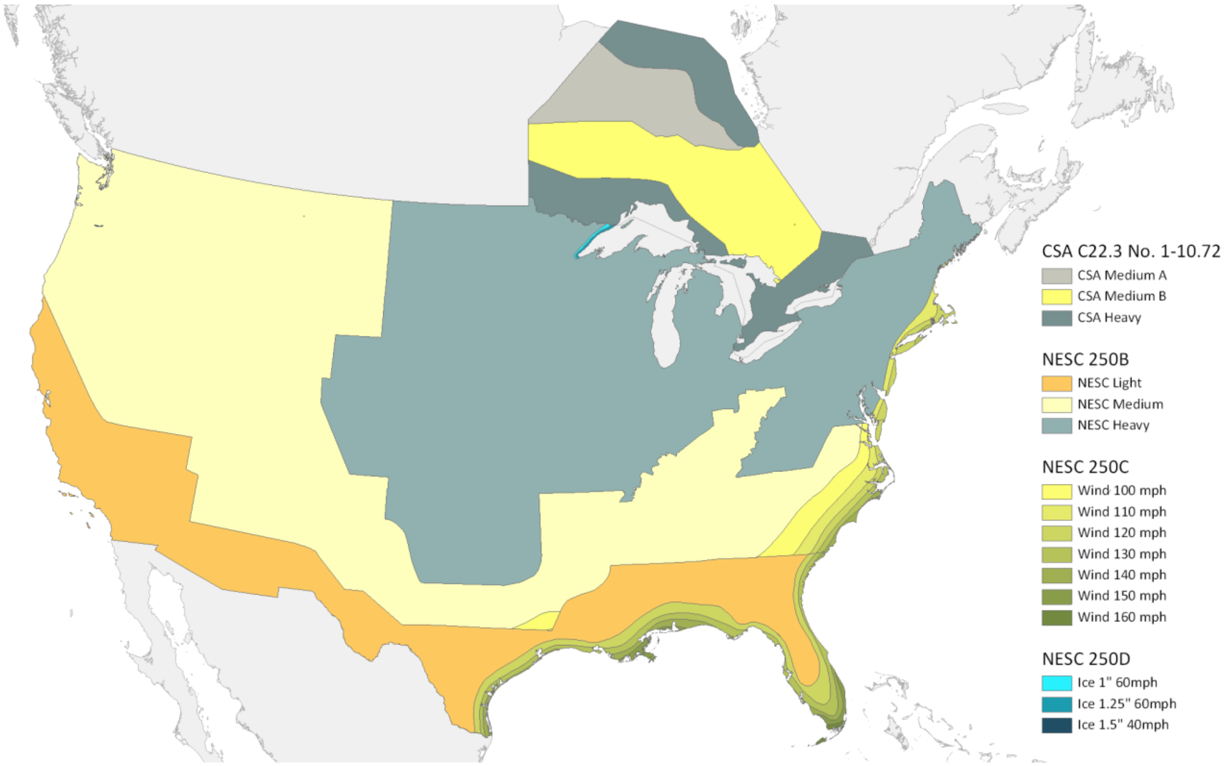
Development of Variable

1. Zones specified by the CSA and NESC were mapped and overlaid with utility service territories.

Industry standards in Canada and the United States dictate minimum requirements for strength of transmission structures, which vary by geographic zone. During design, ice and wind loads are applied to a structure model to analyze strength in terms of percentage of strength capacity used.

The zone boundaries and the required ice and wind load cases are outlined in the Canadian Standards Association (CSA) Overhead Systems Standard C22.3 No. 1-10 for Canada, and the National Electrical Safety Code (NESC) for the United States. The loading zones are illustrated in Figure 8.

Figure 8 CSA and NESC Loading Zones



Utility service territories were overlaid with the above loading zone map. GIS analysis revealed the percentage of a given utility's service territory that fell into each loading zone.

2. Loading capacity was evaluated for a base structure in each zone.

A base transmission structure was identified to represent a typical application throughout the industry. Specifications are outlined in Table 13. Although this structure cannot represent an exact base structure for every utility, it is reasonable for side-by-side comparison of relative structure loading values for utilities in each zone.

Thus, Table 14 represents the loads as a percentage of the maximum allowable for the base transmission structure. For example, the design criteria for CSA 7.2 zone "Medium A" is 73.3% of the maximum load strength of the base structure described in Table 13. The design criteria required for a structure in CSA 7.2 zone "Severe" is 148.9% of the maximum load strength of the base structure described in Table 13, indicating that the base transmission structure would fail in those conditions.

Table 13 Base Transmission Structure Specifications

	Metric		English	
Pole Material	wood			
Pole Length	22.9	m	75	ft
Pole Class	H2			
Span Length	106.7	m	350	ft
Framing	TP-115			
Voltage	115 kV			
Construction Grade	NESC Grade B / CSA Grade 1			
Transmission Conductor Material	795 (26/7) ACSR			
Transmission Design Tension	6000	lb	26.7	kN
Shield Wire Material	3/8" EHS Steel			
Shield Wire Design Tension	2700	lb	12.0	kN

Industry best practice is to consider local historical weather data for transmission line designs, but the deterministic load cases defined by the CSA and NESC provide minimum requirements for each zone. Therefore, the load cases identified in CSA C22.3 No. 1-20 7.2 and NESC Rules 250B, 250C, and 250D were used for analysis. Loading zones with the same names in Canada and the United States are not equivalent, e.g. the CSA “Heavy” zone specifies different accumulated ice and wind loads than the NESC “Heavy” zone. Multipliers, including strength factors for structure components and load factors for ice and wind loads, are also specified in each code and were included in this analysis. PLS-CADD Lite, an engineering modeling software application for transmission and distribution structures, was used to complete nonlinear analysis of the base structure for each zonal load case, outlined in Table 14.

Table 14 Loading Capacity Usage Percentages by Loading Zone

<table>
<tr><td rowspan="5">CSA 7.2</td><td colspan="2">Zone</td><td>Loading [%]</td></tr>
<tr><td colspan="2">Medium A</td><td>73.3</td></tr>
<tr><td colspan="2">Medium B</td><td>81.5</td></tr>
<tr><td colspan="2">Heavy</td><td>103.5</td></tr>
<tr><td colspan="2">Severe</td><td>148.9</td></tr>
<tr><td rowspan="4">NESC 250B</td><td colspan="2">Zone</td><td>Loading [%]</td></tr>
<tr><td colspan="2">Light</td><td>75.3</td></tr>
<tr><td colspan="2">Medium</td><td>49.7</td></tr>
<tr><td colspan="2">Heavy</td><td>66.2</td></tr>
<tr><td rowspan="10">NESC 250C</td><td colspan="2">Wind [mph]</td><td>Loading [%]</td></tr>
<tr><td colspan="2">85</td><td>43.1</td></tr>
<tr><td colspan="2">90</td><td>48.2</td></tr>
<tr><td colspan="2">100</td><td>59.1</td></tr>
<tr><td colspan="2">110</td><td>71.1</td></tr>
<tr><td colspan="2">120</td><td>84.1</td></tr>
<tr><td colspan="2">130</td><td>98.1</td></tr>
<tr><td colspan="2">140</td><td>113.1</td></tr>
<tr><td colspan="2">150</td><td>128.9</td></tr>
<tr><td colspan="2">160</td><td>145.5</td></tr>
<tr><td rowspan="13">NESC 250D</td><td>Ice [in]</td><td>Wind [mph]</td><td>Loading [%]</td></tr>
<tr><td>1.5</td><td>30</td><td>33.7</td></tr>
<tr><td>0.75</td><td>40</td><td>29.2</td></tr>
<tr><td>1</td><td>40</td><td>36.2</td></tr>
<tr><td>1.25</td><td>40</td><td>44.3</td></tr>
<tr><td>1.5</td><td>40</td><td>53.7</td></tr>
<tr><td>0.5</td><td>50</td><td>34.7</td></tr>
<tr><td>0.75</td><td>50</td><td>43.9</td></tr>
<tr><td>1</td><td>50</td><td>54.1</td></tr>
<tr><td>0.5</td><td>60</td><td>48.9</td></tr>
<tr><td>0.75</td><td>60</td><td>61.7</td></tr>
<tr><td>1</td><td>60</td><td>75.9</td></tr>
<tr><td>1.25</td><td>60</td><td>91.7</td></tr>
</table>

3. Loading values were calculated for each utility based on the area and loading percentages.

The area percentages derived from the zone map and utility service territory map were multiplied by loading value percentages from PLS-CADD analysis for each loading zone present in a given utility service territory. These values were summed to produce an overall loading value for each utility. This overall loading value represents (roughly) the minimum design/build structural strength required for the utility's service territory.

Data Sources

1. United States load cases: National Electrical Safety Code (NESC) Rules 250B, 250C, and 250D
2. Canadian load cases: Canadian Standards Association (CSA) Overhead Systems C22.3 No. 1-10 7.2

3. Nonlinear loading models: PLS-CADD Lite Version 15.00
4. GIS mapping software: ArcGIS Pro v2.1, ArcGIS Server 10.5, SQL Server 2014
5. Utility service territories: S&P Global – Platts and Power System Engineering acquired service territories <https://www.platts.com/maps-geospatial>

PLS-CADD Lite Model Inputs

Zonal weather criteria are defined in NESC 250B and CSA 22.3 No. 1-10 7.2 and summarized in Table 15 below. The NESC set includes two additional sets of load cases which do not have counterparts in the CSA. These are Rule 250C: extreme wind loading and Rule 250D: extreme ice with concurrent wind loading. Separate zones were identified for these rules as well.

Table 15 Weather Criteria

		Wire Ice Density		Air Density Factor		Wind Pressure		Wire Ice Thickness		Ambient Temp		NESC Constant	
		[kg/m^3]	[lbs/ft^3]	[Pa/(m/s)^2]	[psf/mph^2]	[Pa]	[psf]	[mm]	[in]	[°C]	[°F]	[N/m]	[lb/ft]
NESC	Heavy	913	57.0	0.613	0.00256	190.5	4	12.7	0.5	-17.8	0	4.38	0.3
	Medium					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
	Light					428.6	9	0.0	0	-1.1	30	0.73	0.05
	Warm Islands (<9000 ft)					428.6	9	0.0	0	10.0	50	0.73	0.05
	Warm Islands (>9000 ft)					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
CSA	Severe	900	56.2	0.613	0.00256	400	8.40	19.0	0.75	-20	-4	N/A	
	Heavy					400	8.40	12.5	0.49	-20	-4		
	Medium A					400	8.40	6.5	0.26	-20	-4		
	Medium B					300	6.30	12.5	0.49	-20	-4		

Load factors and strength factors are summarized in Tables A2 and A3, respectively.

Table 16 Load Factors

	NESC Grade B	CSA Grade 1
Vertical	1.50	4.00
Tansverse - wind	2.50	2.00
Transverse - wire tensions	1.65	2.00
Longitudinal - at deadends (with terminations or tension changes)	1.65	2.00
Longitudinal - general (without terminations or tension changes)	1.10	1.30

Table 17 Strength Factors

	NESC 250B Grade B	CSA Grade 1
Wood Structures	0.65	not specified - accounted for in load factors
Wood Crossarms & Braces	0.65	
Support Hardware	1.0	
Guy Wire	0.9	
Guy Anchor and Foundation	1.0	

STEVEN A. FENRICK

Director of Economics

SUMMARY OF EXPERIENCE AND EXPERTISE

- Leader of PSE's Economics and Market Research group which conducts research in the fields of performance benchmarking, incentive regulation, value-based reliability planning, DSM, load research and forecasting, and survey design and implementation.
- Manages PSE's cost, productivity, and reliability performance benchmarking practice.
- Directs research on value-based reliability planning efforts for electric utilities.
- Expert in performance-based ratemaking and incentive regulation.
- Directs economic research on investigating the impacts and costs/benefits of DSM programs and designing statistically robust pilot designs.

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc. – Madison, WI (2009 to present)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, load research, load forecasting, end-use surveys, and market research.

- Leads research, on an annual basis, with over a dozen electric utilities in evaluating cost, productivity, and reliability performance and uncovering methods to improve their operations.
- Benchmarking consultant to the Ontario Energy Board regarding their 3rd Generation Incentive Regulation Plan for the last two years.
- In the process of designing and analyzing DSM pilot projects at over 25 electric utilities across the country.
- Testimony experience regarding performance value-based reliability planning, benchmarking and productivity analysis.
- Has given several presentations on performance benchmarking and productivity analysis, costs and benefits of DSM programs, and measurement and verification (M&V) techniques.
- Key speaker at EUCI conferences regarding cost and reliability performance evaluation and productivity analysis of distribution utilities.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling.

STEVEN A. FENRICK

EDUCATION

University of Wisconsin - Madison, WI
Master of Science, Agriculture and Applied Economics

University of Wisconsin - Madison, WI
Bachelor of Science, Economics (Mathematical Emphasis)

Publications & Papers

- "Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- "Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)
- "Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).
- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- "The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).
- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper*.
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.

STEVEN A. FENRICK

Expert Witness Experience

- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".
- Expert Witness presentation to Connecticut Governors "Two Storm Panel", 2012.
- Docket No. EB-2012-0064, Toronto Hydro's Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2017.
- Wisconsin Manager's Meeting, "Reliability Target Setting Using Econometric Benchmarking". November 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2016.
- Wisconsin Electric Cooperative Association (WECA) Conference, "An Introduction to Peak Time Rebates". September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2015.
- EUCI conference chair, 2015. "Evaluating the Performance of Gas and Electric Distribution Utilities."
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2014.
- Cooperative Exchange Conference, Williamsburg VA. "Smart Thermostat versus AC Direct Load Control Impacts". August 2014.
- EUCI conference chair in Chicago. "The Economics of Demand Response". February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2013.
- EUCI conference chair in Chicago. "Evaluating the Performance of Gas and Electric Distribution Utilities." August 2013.
- Presentation to the Ontario Energy Board, "Research and Recommendations on 4th Generation Incentive Regulation".
- Presentation to the Canadian Electricity Association's best practice working group. 2013

- Conference chair for EUCI conference in March 2013 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".
- Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.
- Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

FORM A

Proceeding:..........................

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Steven A. Fenrick (*name*). I live at Verona (*city*), in the State (*province/state*) of Wisconsin .

2. I have been engaged by or on behalf of Hydro One (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 5/3/18

St Fen

Signature

UNIFORM TRANSMISSION RATES AND CHARGE DETERMINANTS

1. OVERVIEW

In Ontario there are five licensed transmitters: Hydro One Networks Inc., Canadian Niagara Power Inc., Five Nations Energy Inc., B2M Limited Partnership, and Hydro One Sault Ste. Marie. Transmission rates in Ontario are established on a uniform basis for all five licensed transmitters in accordance with RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044, dated April 30, 2002. The current Ontario Uniform Transmission Rates ("UTR") Schedules were effective January 1, 2018 as approved in the Ontario Energy Board's ("OEB") EB-2017-0359 Decision and Order issued February 1, 2018.

UTRs are established by aggregating the revenue requirement for the five transmitters and allocating the revenue requirements to the UTR Rate Pools: Network, Line Connection and Transformation Connection, based on a cost allocation study conducted by Hydro One on a regular basis. This study determines the proportionate allocation of the revenue requirement of the transmitters to the appropriate rate pools. The exception is B2M Limited Partnership whose costs are 100% allocated to the Network pool as the assets only provide Network services. The costs are then divided by forecast consumption (charge determinants) of each transmitter to establish the UTRs.

2. CURRENT UNIFORM TRANSMISSION RATES

Table 1 illustrates the calculation of the current 2018 UTR. The complete 2018 rate schedule can be found at Exhibit D, Tab 3, Schedule 1.

Table 1 - 2018 Interim Uniform Transmission Rates and Revenue Disbursement Allocators

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$5,408,935	$1,426,550	$2,991,661	$9,827,155
CNPI	$2,557,819	$674,504	$1,414,878	$4,647,201
H1N SSM	$22,327,484	$5,887,821	$12,350,631	$40,565,936
H1N	$831,494,343	$219,267,431	$459,947,909	$1,510,709,683
B2MLP	$37,500,000	$0	$0	$37,500,000
All Transmitters	$899,288,581	$227,256,306	$476,705,079	$1,603,249,975

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	3.61	0.95	2.34	
FNEI Allocation Factor	0.00601	0.00628	0.00628	
CNPI Allocation Factor	0.00284	0.00297	0.00297	
GLPT Allocation Factor	0.02483	0.02591	0.02591	
H1N Allocation Factor	0.92462	0.96484	0.96484	
B2MLP Allocation Factor	0.04170	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

The total rates revenue requirement to being recovered through the UTR for 2018 is $1,603,249,975, up 5.3% from the total 2017 approved transmission rates revenue requirement. The combined UTR for 2018, effective January 1, 2018, is $6.90/kW, a $0.37/kW or 5.7% increase relative to the 2017 UTR ($6.53/kW). The 2018 UTR are based on the approved revenue requirement and pool load forecasts in the following OEB proceedings:

- Five Nations Energy Inc. (EB-2016-0231) issued January 18, 2018.
- Canadian Niagara Power Inc. (EB-2014-0204) issued June 25, 2015 with approved 2016 order under EB-2015-0354, issued January 14, 2016 and confirmed on November 9, 2017 (EB-2016-0160).
- Hydro One Networks Sault Ste. Marie (EB-2016-0356) issued September 28, 2017.
- Hydro One Networks Inc. (EB-2016-0160) Decision and Order issued December 20, 2017.
- B2M Limited Partnership (EB-2015-0026) Decision and Order issued on December 29, 2015.

3. CHARGE DETERMINANTS

The charge determinants of the five licensed transmitters for the Network, Line Connection and Transformation Connection rate pools are used by the OEB to determine UTRs. As Hydro One Sault Ste. Marie (“HOSSM”) is not revising the demand forecast by delivery point, the charge determinants for the 2019 will remain the same as were used for the approved 2018 UTRs as shown in Table 2.

Table 2 - Charge Determinants (in MWs)

Transmitter	Network	Line Connection	Transformation Connection
HOSSM	3,498.236	2,734.624	635.252

4. PROPOSED UNIFORM TRANSMISSION RATES

Table 3 demonstrates the calculation of HOSSM's proposed revenue requirement for 2019.

Table 3 - Calculation of HOSSM's 2019 Revenue Requirement for UTRs

Item	Amount	Support Reference
Base Revenue Requirement	$39, 778, 120	EB-2016-0356 Decision and Order, page 11 – HOSSM's 2016 approved revenue requirement and charge determinants will remain in effect. EB-2015-0337, page 3 – 2016 approved base revenue requirement
2019 Base Revenue Requirement using Proposed Revenue Cap Index	$40,255,457	Methodology found in Exhibit D, Tab 1, Schedule 1 $39,778,120 (2016 Base revenue requirement) X 1.012 (proposed Revenue Cap Index – Exhibit D, Tab 1, Schedule 1)
Deferral and Variance Account ("DVA") Disposition	$94,909 credit	Exhibit E, Tab 1, Schedule 1
2019 Total Revenue Requirement for UTRs	$40,160,548	Base revenue requirement - $40,255,457 DVA aggregated amount – ($94,909) 2019 Total Revenue Requirement for UTRs

The projected 2019 UTR calculations incorporates HOSSM's revenue requirement and charge determinants proposed in this application, and assumes that the revenue requirement and charge determinant values approved for the other transmitters in the OEB's most recent Rate Order (EB-2017-0359) remain unchanged.

1 **Table 4 - Proposed 2019 UTRs**

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$5,408,935	$1,426,550	$2,991,661	$9,827,155
CNPI	$2,557,819	$674,504	$1,414,878	$4,647,201
H1N SSM	$22,104,359	$5,828,982	$12,227,207	$40,160,548
H1N	$831,494,343	$219,267,431	$459,947,909	$1,510,709,683
B2MLP	$37,500,000	$0	$0	$37,500,000
All Transmitters	$899,065,455	$227,197,468	$476,581,656	$1,602,844,587

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.61**	**0.94**	**2.34**	
FNEI Allocation Factor	**0.00602**	**0.00628**	**0.00628**	
CNPI Allocation Factor	**0.00284**	**0.00297**	**0.00297**	
H1N SSM Allocation Factor	**0.02459**	**0.02566**	**0.02566**	
H1N Allocation Factor	**0.92484**	**0.96509**	**0.96509**	
B2MLP Allocation Factor	**0.04171**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

2

2019 BILL IMPACTS

1. INTRODUCTION

In Exhibit D, Tab 2, Schedule 1, Hydro One Sault Ste. Marie ("HOSSM") calculates the impact of this application on Ontario Uniform Transmission Rates ("UTRs"). As demonstrated in that schedule, there is a very small impact on the Line Connection pool of the UTRs as a result of this application. The Network and Transformation Connection rates are not impacted.

Overall, HOSSM's proposed 2019 revenue requirement results in a 0.025% decrease in Ontario's total transmission revenue requirement compared to the currently approved value[1]. In principle, the change in transmission revenue requirement has an impact on the Retail Transmission Service Rates ("RTSR") for all distribution customers in Ontario. The impact of HOSSM's proposed 2019 transmission revenue requirement on a customer's monthly electricity bill can be shown through illustrative bill impact calculations for a Local Distribution Company ("LDC") whose RTSR incorporates approved 2018 UTRs, such as Hydro One Networks' Norfolk service area[2]. For the purposes of this analysis, a typical residential customer is assumed to consume 750 kWh per month, and a typical general service <50 kW customer is assumed to consume 2,000 kWh per month. As shown in Table 1 and Table 2 below, HOSSM's proposed transmission revenue requirement change is small and therefore results in virtually no impact on typical residential and general service < 50 kW customers' monthly electricity bills.

---

[1] Decision and Rate Order, 2018 Uniform Transmission Rates, EB-2017-0359
[2] Decision and Rate Order, 2018 Distribution Rates for Areas Formerly Served by Haldimand County Hydro Inc., Norfolk Power Distribution Ltd., and Woodstock Hydro Services Inc., EB-2017-0050

Table 1 - Impact of HOSSM's Proposed 2019 Transmission Revenue Requirement on a Typical Residential Customer's Monthly Electricity Bill

Residential (Hydro One - Norfolk Service Area)	**Unit**	**Charge per Unit**	**Charge per Month**
Monthly Consumption	kWh	750	
Loss Factor		1.0564	
Electricity (Off-Peak) - Including cost of losses	$ per kWh	$0.065	$33.47
Electricity (Mid-Peak) - Including cost of losses	$ per kWh	$0.094	$12.66
Electricity (On-Peak) - Including cost of losses	$ per kWh	$0.132	$18.83
Smart Metering Entity Charge	$ per month	$0.57	$0.57
Distribution Fixed Monthly Service Charge	$ per month	$32.79	$32.79
Rate Riders – Fixed	$ per month	-$0.49	-$0.49
Distribution Volumetric Charge - Including LV Charge	$ per kWh	$0.0064	$4.80
Rate Riders - Volumetric	$ per kWh	$0.0043	$3.23
Transmission Network Service Charge	***$ per kWh***	***$0.0067***	***$5.31***
Transmission Connection Service Charge	***$ per kWh***	***$0.0038***	***$3.01***
Standard Supply Service Charge	$ per month	$0.25	$0.25
Wholesale Market Service Charge	$ per kWh	$0.0036	$2.85
Rural & Remote Rate Protection Charge	$ per kWh	$0.0003	$0.24
Total Monthly Bill (Before Taxes & Rebates)			**$117.51**
Amount of Bill Related to Transmission Rates			$8.32
Percentage Change in Transmission Rev Req - 2018 to 2019			-0.025%
Monthly $ Change Resulting from Transmission Rate Change			**$0.00**
% Bill Change Resulting from Transmission Rate Change			**0.00%**

Rates effective May 1, 2018

Table 2 - Impact of HOSSM's Proposed 2019 Transmission Revenue Requirement on a Typical General Service <50 kW Customer's Monthly Electricity Bill

GS<50 kW (Hydro One - Norfolk Service Area)	Unit	Charge per Unit	Charge per Month
Monthly Consumption	kWh	2,000	
Loss Factor		1.0564	
Electricity (Off-Peak) - Including cost of losses	$ per kWh	$0.065	$89.27
Electricity (Mid-Peak) - Including cost of losses	$ per kWh	$0.094	$33.76
Electricity (On-Peak) - Including cost of losses	$ per kWh	$0.132	$50.20
Smart Metering Entity Charge	$ per month	$0.57	$0.57
Distribution Fixed Monthly Service Charge	$ per month	$49.98	$49.98
Rate Riders - Fixed	$ per month	-$0.74	-$0.74
Distribution Volumetric Charge - Including LV Charge	$ per kWh	$0.0164	$32.80
Rate Riders - Volumetric	$ per kWh	$0.0040	$8.00
Transmission Network Service Charge	***$ per kWh***	***$0.0062***	***$13.10***
Transmission Connection Service Charge	***$ per kWh***	***$0.0033***	***$6.97***
Standard Supply Service Charge	$ per month	$0.25	$0.25
Wholesale Market Service Charge	$ per kWh	$0.0036	$7.61
Rural & Remote Rate Protection Charge	$ per kWh	$0.0003	$0.63
Total Monthly Bill (Before Taxes & Rebates)			**$292.40**
Amount of Bill Related to Transmission Rates			$20.07
Percentage Change in Transmission Rev Req - 2018 to 2019			-0.025%
Monthly $ Change Resulting from Transmission Rate Change			**-$0.01**
% Bill Change Resulting from Transmission Rate Change			**0.00%**

Rates effective May 1, 2018

Ontario

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

DECISION AND RATE ORDER

EB-2017-0359

2018 UNIFORM TRANSMISSION RATES

BEFORE: **Ken Quesnelle**
Presiding Member

Emad Elsayed
Member

February 1, 2018

TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY

The Ontario Energy Board (OEB) established the EB-2017-0359 proceeding on its own motion to issue the 2018 Uniform Transmission Rates (UTR).

There are five licensed electricity transmitters in Ontario that recover their revenues through Ontario's UTR: Canadian Niagara Power Inc., Hydro One Networks Sault Ste. Marie (formerly Great Lakes Power Transmission Inc.), Five Nations Energy Inc., Hydro One Networks Inc. and B2M Limited Partnership. The OEB approves the revenue requirements and charge determinants of the individual transmitters in separate proceedings and uses them to calculate the UTR.

The revenue requirements of the five transmitters are allocated to three transmission rate pools, Network, Line Connection and Transformation Connection on the basis of a cost allocation study conducted annually by Hydro One Networks Inc. The costs are then divided by forecast consumption (charge determinants) to establish the UTR. The Independent Electricity System Operator (IESO) charges these rates to all wholesale market participants, including electricity distributors.

The total rates revenue requirement to be recovered through the UTR for 2018 is $1,603,249,975, up 5.3% from the total 2017 approved transmission rates revenue requirement.

The combined UTR for 2018, effective January 1, 2018, is $6.90/kW, a $0.37/kW or 5.7% increase relative to the 2017 UTR ($6.53/kW).

The impact of this increase may take some time to materialize, and will vary depending on the customer mix and load characteristics in the different service areas and the proportion of power withdrawn by individual distributors from the bulk transmission system.

Electricity distributors directly connected to the transmission system recover transmission costs from their customers through Retail Transmission Service Rates (RTSR), which are established for each rate class annually, some on January 1 and some on May 1. The new UTR will be taken into account when new RTSR are approved effective January 1, 2018 or May 1, 2018, depending on when a specific distributor makes its annual rate adjustments. For any distributor whose rates for 2018 have already been established, the use of variance accounts will track differences between a distributor’s transmission costs and the associated revenues it receives from its customers, in order to ensure that its customers pay the true cost of transmission service over time.

2. THE PROCESS

The total revenue to be recovered for transmission services in 2018 is derived from the OEB's decisions for the revenue requirements and charge determinants for each of the five transmitters in Ontario. The findings in this Decision and Rate Order involve only the implementation of findings in these previous decisions. The OEB has therefore determined that no person will be adversely affected in a material way by the outcome of this proceeding. In accordance with section 21(4)(b) of the Ontario Energy Board Act, this matter has been determined without a hearing.

3. 2018 UNIFORM TRANSMISSION RATES

Hydro One submitted its EB-2017-0359 Draft Revenue Requirement and Charge Determinant Order (DRR/CDO), on December 4, 2017, which included consolidated information from the other four Ontario transmitters and a calculation of the 2018 UTR.

This Decision and Rate Order incorporates the OEB's findings in the most recent approved revenue requirement and pool load forecasts (charge determinants) for each of the Ontario transmitters: Five Nations Energy Inc., Canadian Niagara Power Inc., Hydro One Networks Sault Ste. Marie, Hydro One Networks Inc. and B2M Limited Partnership as shown below:

- Five Nations Energy Inc. (EB-2016-0231) issued January 18, 2018.
- Canadian Niagara Power Inc. (EB-2014-0204) issued June 25, 2015 with approved 2016 order under EB-2015-0354, issued January 14, 2016 and confirmed on November 9, 2017 (EB-2016-0160).
- Hydro One Networks Sault Ste. Marie (EB-2016-0356) issued September 28, 2017.
- Hydro One Networks Inc. (EB-2016-0160) Decision and Order issued December 20, 2017.
- B2M Limited Partnership (EB-2015-0026) 2018 Decision and Order issued on December 29, 2015[1].

The individual 2018 revenue requirement and charge determinant amounts for each of the five Ontario transmitters in the Ontario transmission rate pool were consolidated to arrive at the 2018 UTR and revenue allocators as shown in Appendix A.

[1] B2M LP requested an update of its 2018 Revenue Requirement by letter dated December 20, 2017 (EB-2017-0380). This update is not reflected in this Decision and Rate Order since there is insufficient time for the proceeding to be completed before this 2018 UTR Decision and Rate Order.

4. FINDINGS

The OEB finds that the UTR calculations attached as Appendix A to this Decision and Rate Order, appropriately reflect the OEB's Decisions for all of the Ontario transmitters in the 2018 transmission rate pool.

As the B2M LP application for 2018 transmission revenue requirement is still under consideration by the OEB[2], the OEB will declare the 2018 UTR as interim. This determination of interim rates is made without prejudice to the OEB's decision on B2M LP's application and should not be construed as predictive, in any way whatsoever, of the OEB's final determination of the effective date for revenue requirement arising from the application.

[2] EB-2017-0380

5. ORDER

THE BOARD ORDERS THAT:

1. The revenue requirements by rate pool and the Uniform Transmission Rates (UTR) and revenue allocators for rates effective January 1, 2018 as shown in Appendix A, are approved on an interim basis.

2. The 2018 UTR are to be implemented as of January 1, 2018.

3. The 2018 Ontario Uniform Transmission Rate Schedules, attached as Appendix B, are approved.

DATED at Toronto February 1, 2018.

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

2018 Uniform Transmission Rates

and

Revenue Disbursement Allocators

EB-2017-0359

Decision and Rate Order

February 1, 2018

2018 Interim Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2018 to December 31, 2018)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$5,408,935	$1,426,550	$2,991,661	$9,827,155
CNPI	$2,557,819	$674,504	$1,414,878	$4,647,201
H1N SSM	$22,327,484	$5,887,821	$12,350,631	$40,565,936
H1N	$831,494,343	$219,267,431	$459,947,909	$1,510,709,683
B2MLP	$37,500,000	$0	$0	$37,500,000
All Transmitters	$899,288,581	$227,256,306	$476,705,079	$1,603,249,975

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	3.61	0.95	2.34	
FNEI Allocation Factor	0.00601	0.00628	0.00628	
CNPI Allocation Factor	0.00284	0.00297	0.00297	
GLPT Allocation Factor	0.02483	0.02591	0.02591	
H1N Allocation Factor	0.92462	0.96484	0.96484	
B2MLP Allocation Factor	0.04170	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2016-0231 dated January 18, 2018.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015.

Note 3: H1N SSM 2017 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2016-0356, issued September 28, 2017.

Note 4: H1N Rates Revenue Requirement (including 2017 Foregone Revenue) per OEB Decision EB-2016-0160 dated December 20, 2017.

Note 5: H1N Charge Determinants per OEB Decision EB-2016-0160, issued November 23, 2017.

Note 6: B2M LP 2018 Revenue Requirement per OEB Decision and Order EB-2015-0026 dated December 29, 2015.

Note 7: Calculated data in shaded cells.

Appendix B

2018 Uniform Transmission Rate Schedules

EB-2017-0359

Decision and Rate Order

February 1, 2018

2018 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2016-0160
EB-2017-0359

The rate schedules contained herein are interim and shall be effective and implemented as of January 1, 2018.

Issued: February 1, 2018
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Interim Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	
$ Per kW of Network Billing Demand [1,2]	3.61
Line Connection Service Rate (PTS-L):	
$ Per kW of Line Connection Billing Demand [1,3]	0.95
Transformation Connection Service Rate (PTS-T):	
$ Per kW of Transformation Connection Billing Demand [1,3,4]	2.34

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998.. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

REGULATORY ACCOUNTS OVERVIEW

1. DEFERRAL AND VARIANCE ACCOUNTS OVERVIEW

Hydro One Sault Ste. Marie ("HOSSM") is requesting approval for continuance of the following deferral/variance accounts:

- Other Regulatory Asset Account 1508;
  - Sub-Accounts:
    - Infrastructure Investment;
    - Green Energy Initiatives and Preliminary Planning Costs;
    - Property Tax and Use and Occupation Permit Fee Variance;
    - International Financial Reporting Standards ("IFRS") Gains and Losses; and
    - Ontario Energy Board ("OEB") Cost Assessments;
- Based upon the Accounting Procedures Handbook, HOSSM will continue to maintain account 1595 related to previously approved regulatory asset recovery; and
- Described in the OEB's 2008 report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, a 50/50 sharing of impacts of legislated tax changes from a utility's tax rates embedded in its OEB approved base rate known at the time of application. HOSSM is proposing to maintain in the rebasing deferral period a sub-account within account 1592 to capture these impacts.

As described in Exhibit A, Tab 2, Schedule 1, in the event HOSSM encounters unforeseen events which meet the three defined eligibility criteria of Causation, Materiality and Prudence, Hydro One will record the amounts in a Z-factor deferral account (Account 1572) for future prudency review and disposition approval by the OEB in a future rate filing..

2. DISBURSAL OF DEFERRAL ACCOUNTS

HOSSM is requesting approval to disburse the balances in the following accounts:
Five sub-accounts of account 1508:

- Comstock Claim;
- Property Tax and Use and Occupation Permit Fee Variances;
- Bulk Energy System ("BES") Definitional Change;
- OEB Cost Assessment Variances; and
- In-service Addition Net Cumulative Asymmetrical Variance Account

HOSSM has provided additional details in Exhibit E, Tab 1, Schedule 2 regarding the establishment and approval of new Deferral and Variance Accounts

2.1 PROPOSED DISBURSAL METHODOLOGY

Account 1595 was originally a debit balance being disbursed over a 3 year period from 2015-2017 as per the Board-Approved Settlement Agreement related to EB-2014-0238. The repayment period began on January 1, 2015 with the implementation of Uniform Transmission Rates ("UTR") for the 2015 calendar year, continuing through 2016 and 2017, with disbursements completed as of December 31, 2017. However for 2018, the amount being dispersed annually in 2015-2017 remained in UTR, thus resulting in an over-collection of this balance by HOSSM. Subject to the approval of the various account balances that HOSSM is seeking to disburse as part of this Application, it is HOSSM's position that the most administratively efficient method to disburse the various account balances would be to aggregate the balance of all accounts and disburse them in 2019.

The total amount HOSSM is seeking to disburse is a credit balance of $94,909. This includes all of the balances sought for approval for the accounts listed in section 2.0 above, as well as forecasted carrying charges for 2018. All account balances HOSSM is seeking to disburse, inclusive of all carrying charges, would be cleared in 2019 under this proposal. This aggregation approach is consistent with prior rate applications, and is described in more detail in Exhibit E, Tab 1, Schedule 3.

HOSSM has provided a continuity schedule of deferral and variance accounts at Exhibit E, Tab 1, Schedule 4 for the years 2014 to 2018.

GOVERNMENT OF
BATCHEWANA FIRST NATION OF OJIBWAYS
RANKIN RESERVE 15 D
GOULAIS BAY RESERVE 15 A
OBADJIWAN RESERVE 15 E
WHITEFISH ISLAND 15

Administration Office: 236 Frontenac Street
Rankin Reserve 15D
Batchewana First Nation, ON P6A 6Z1
Ph: (705) 759-0914 / Fax: (705) 759-9171
www.batchewana.ca

July 7 2016

Via Facsimile: 416-440-7656

Ms. Mary Anne Aldred
General Counsel & Vice President, Legal Services and Strategic Policy
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

- and –

Ms. Lynne Anderson
Vice-President, Applications
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto, Ontario, Canada
M4P 1E4

Subject: EB-2016-0050

Dear Ms. Aldred and Ms. Anderson:

Further to your continued processing of this application, Batchewana First Nation wishes to inform the Ontario Energy Board that Great Lake Power Transmission does not have a valid Section 28(2) permit for a purported two hundred foot (200') easement over our First Nation affecting their former North Transmission A and Transmission B corridors that run west to east and were located on Rankin Reserve 15D south of Old Garden River Road.

Permits that were issued by the predecessors to the Department of Indigenous and Northern Affairs Canada ("INAC") expired on December 31 2008 and they have not been renewed. We can indicate to both of you that there is no immediate expectation that Batchewana First Nation will concur with a renewal of these permits without additional discussions between our First Nation, INAC and both proponents. Batchewana First Nation is of the opinion that GLPT has been trespassing on Rankin Reserve 15D since the expiry of the Section 28(2) permits on December 31 2008.

Batchewana First Nation has specific concerns with the South Transmission easement, consisting of sixty-six feet also running west to east, and we will continue to investigate whether or not this easement remains in effect and we will advise you of our findings once our investigation has been completed.

We will provide notice to both of the proponents in due course through direct correspondence with both of them that will be issued shortly.

In the meantime, we would request a meeting with the Ontario Energy Board at your earliest convenience to discuss this matter and we would strongly advise that you not proceed with any approval of this application until such time as all matters with Batchewana First Nation have been resolved to our satisfaction.

To establish a meeting date and time please feel free to contact me at (705) 759-0914 x 202 or alternatively at (705) 257-1696.

Miigwetch,

Chief Dean Sayers

cc: Batchewana First Nation Council
Kim Lambert, Chief Executive Officer
William B. Henderson, Legal Counsel
Wayne Greer, President, Aboriginal Business Network

ESTABLISHMENT AND APPROVAL OF NEW DEFERRAL AND VARIANCE ACCOUNTS

1. INTRODUCTION

As at December 31, 2017, Hydro One Sault Ste. Marie ("HOSSM") has seven active sub-accounts of Account 1508 – Other Regulatory Assets. The seven sub-accounts are related to:

i) Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs[1];
ii) Comstock Claim;
iii) Property Tax and Use and Occupation Permit Fee Variances;
iv) International Financial Reporting Standards ("IFRS") Gains and Losses;
v) Incremental costs related to addressing an upcoming change to the definition of the Bulk Electric System ("BES");
vi) Ontario Energy Board ("OEB") Cost Assessment Variances; and
vii) In-service Addition Net Cumulative Asymmetrical Variance Account.

2. INFRASTRUCTURE INVESTMENT, GREEN ENERGY INITIATIVES AND PRELIMINARY PLANNING COSTS

As described in EB-2014-0238[2], HOSSM is using this sub-account to capture Operations Maintenance & Administration ("OM&A") expenses and capital expenses related to

[1] This account was approved by the OEB in its decision on EB-2009-0409, which was an application by HOSSM to establish a deferral account to record expenses related to renewable generation connection, system planning, and infrastructure investment arising from the *Green Energy and Green Economy Act, 2009*.

renewable generation connection, system planning, and infrastructure investment arising from the *Green Energy and Green Economy Act, 2009* ("GEA"). HOSSM has not had a requirement to use this account since EB-2014-0238, and therefore the account balance remains at $0.

HOSSM is requesting to maintain this variance account for future use, as required.

3. COMSTOCK CLAIM

In the EB-2014-0238 settlement agreement approved by the OEB on November 19, 2014, the parties agreed that HOSSM would disburse the December 31, 2013 balance in this account, plus 2014 carrying charges for a total of $2,354,305. The parties also agreed that HOSSM would continue use of the account to capture costs incurred after December 31, 2013, until the matter was resolved. HOSSM incurred additional costs in 2014 and 2015 to resolve the Comstock claim, and is forecasting no further costs to be incurred. The costs incurred were primarily legal costs related to negotiating and executing a full and final mutual release with Comstock and its Receiver, which was signed in February 2015.

Table 1 below demonstrates the evolution of this account up to December 31, 2018.

---

[2] EB-2014-0238 – Great Lakes Power Transmission Rate Application for 2015 and 2016 rates

Table 1 - Account 1508 - Comstock

Year	Opening Balance	Costs Incurred	Transfers	Cumulative Costs	Carrying Charges	Transfers	Cumulative Carrying Charges	Closing Account Balance
2010	$0	$1,660,623	$0	$1,660,623	$0	$0	$0	$1,660,623
2011	1,660,623	106,634	-	1,767,257	24,920	-	24,920	1,792,177
2012	1,792,177	375,800	-	2,143,057	27,855	-	52,775	2,195,833
2013	2,195,833	93,664	-	2,236,721	31,928	-	84,704	2,321,425
2014	2,321,425	80,404	-	2,317,126	33,055	-	117,759	2,434,884
2015	2,434,884	15,075	(2,261,466)	70,735	789	(92,839)	25,709	96,444
2016	96,444	-	-	70,735	778	-	26,487	97,222
2017	97,222	-	-	70,735	849	-	27,336	98,071
2018	98,071	-	-	70,735	1,268	-	28,604	99,338
				$70,735			**$28,604**	**$99,338**

HOSSM is seeking to disburse the forecast December 31, 2018 debit balance of $99,338, inclusive of carrying charges, as described in Exhibit E, Tab 1, Schedule 3. As the matter has now been resolved, HOSSM is not seeking continuation of this sub-account.

4. PROPERTY TAX AND USE AND OCCUPATION PERMIT FEE VARIANCES

As described in previous rate applications, HOSSM is using this sub-account to capture variances in payments in lieu of taxes paid to First Nations as compared to the base cost embedded in revenue requirement for each year.

In 2015, HOSSM negotiated an amendment to an existing agreement with one of its First Nation partners, establishing a 25 year agreement with an option for a 25 year renewal upon expiry. The amendment came into effect January 1, 2016 and resulted in a marginal increase in the annual fee. As a result, HOSSM made $146,167 in payments in lieu of taxes to First Nations compared to the $128,800 which was the base cost embedded in revenue requirement for 2016. HOSSM has recorded the incremental fee in this sub-account for disbursal. Table 2 below demonstrates the amounts recorded in this account, inclusive of carrying charges.

Table 2 - Use and Occupation Permit Fee Variances

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2016	$0	$17,367	$17,367	$88	$88	$17,454
2017	17,454	-	17,367	208	296	17,663
2018	17,663	-	17,367	311	607	17,974
			$17,367		**$607**	**$17,974**

HOSSM is seeking to disburse the forecast December 31, 2018 debit balance of $17,974, inclusive of carrying charges, as described in Exhibit E, Tab 1, Schedule 3. However, HOSSM is proposing to cease recording amounts in this account to the extent they are directly associated with the January 1, 2016 amendment variance described above in section 4.0.

In the OEB's Decision and Order in proceeding EB-2009-0408, a variance account was approved to track any variances between the approved payments in lieu of taxes and any new payments to First Nations in lieu of taxes that may be negotiated before Great Lakes Power Transmission's ("GLPT" – now known as HOSSM) next rate application. At the time it was noted that GLPT was still negotiating with at least one First Nation group regarding payments in lieu of taxes. It was also mentioned in subsequent OEB proceedings; EB-2010-0291, EB-2012-0300, and EB-2014-0238, that GLPT was using this sub-account to capture variances in payments in lieu of taxes paid to First Nations as compared to the base cost embedded in revenue requirement for each year.

In the Hydro One's Mergers, Acquisitions, Amalgamations and Divestitures ("MAADs") application EB-2016-0050, Batchewana First Nations Council, submitted a letter to the OEB dated July 7, 2016 (found as Appendix A), stating that

> "*Great Lakes Power Transmission does not have a valid Section 28(2) permit for a purported two Hundred foot (200') easement over our First Nation affecting their former North Transmission A and Transmission B corridors that run west to east and were located on Rankin Reserve 15D south of Old Garden River Road*".

In 2017, negotiations with Batchewana First Nations resulted in total costs incurred by HOSSM of $3,708,585. This cost is being tracked in this account.

HOSSM expects there will be additional payments in lieu of taxes to Batchewana First Nations; and, as such HOSSM is requesting to maintain this variance account for future use, as required.

5. IFRS GAINS AND LOSSES

As part of the EB-2014-0238 settlement agreement approved by the Board on November 19, 2014, the OEB authorized HOSSM to continue to maintain a deferral account to record costs in respect of gains and losses resulting from premature asset component retirements. HOSSM incurred a loss on disposal in both 2015 and 2016, net of proceeds from disposition. However, HOSSM is not seeking to disburse the balance of this account at this time as rate base will not be rebased as a part of this application, therefore the amounts disposed will remain in HOSSM's rate base for the life of the rebasing deferral period (10 years)[3] consistent with the rate making methodology applied in this application.

6. INCREMENTAL COSTS RELATED TO ADDRESSING THE CHANGE TO THE DEFINITION OF THE BULK ELECTRIC SYSTEM ("BES")

As part of the EB-2014-0238 settlement agreement approved by the OEB on November 19, 2014, the OEB approved continuation of HOSSM's deferral account which was established to capture incremental costs relating to addressing an upcoming change to the definition of the BES. It was agreed that HOSSM should establish two sub-accounts under this deferral account; one for OM&A expenses and one for capital expenses. HOSSM has only recorded costs in the OM&A sub-account. Table 3 below outlines the amounts recorded in this account to date.

[3] Ten year rebasing deferral period was approved in the MAADs application EB-2016-0050 Decision and Order dated October 13, 2016.

Table 3 - BES Variance Account Costs – OM&A

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2013	$0	$6,928	$6,928	$33	$33	$6,961
2014	6,961	12,627	19,555	133	166	19,721
2015	19,721	-	19,555	233	399	19,955
2016	19,955	-	19,555	215	615	20,170
2017	20,170		19,555	235	850	20,405
2018	20,405		19,555	351	1,200	20,755
			$19,555		**$1,200**	**$20,755**

This sub-account was established to track and record prudently incurred costs related to addressing changes to the BES definition which were effective July 1, 2016. HOSSM is compliant with all applicable North American Reliability Corporation ("NERC") standards, including those associated with the updated BES definition, and therefore HOSSM no longer requires continuation of this sub-account. In light of this, HOSSM is seeking to disburse the forecast December 31, 2018 debit balance of $20,755, inclusive of carrying charges, as described in Exhibit E, Tab 1, Schedule 3. Given the work completion, HOSSM is not seeking continuation of this sub-account.

7. OEB COST ASSESSMENT VARIANCES

As described in the OEB's letter dated February 9, 2016 addressed to all Regulated Entities subject to the OEB's Cost Assessment, the OEB established a variance account for electricity distributors and transmitters to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model effective April 1, 2016.

The base cost included in HOSSM's currently approved revenue requirement is $107,095, while the costs incurred for 2016 and 2017 was $74,319 and $57,289 respectively. HOSSM has recorded the variances in this sub-account since 2016, and is forecasting a balance owing to ratepayers of $84,866 in this sub-account at December 31, 2018, inclusive of carrying charges. Table 4 below outlines the amounts recorded in this account to date.

Table 4 - OEB Cost Assessment Variances

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2016	$0	($32,776)	($32,776)	($120)	($120)	($32,896)
2017	(32,896)	(49,806)	(82,582)	(685)	(805)	($83,386)
2018	(83,386)	-	(82,582)	(1,480)	(2,285)	($84,866)
			($82,582)		**($2,285)**	**($84,866)**

HOSSM is seeking to disburse the forecast December 31, 2018 credit balance of $84,866, inclusive of carrying charges, as described in Exhibit E, Tab 1, Schedule 3.
HOSSM will continue to record variance amounts and their associated carrying charges in this account on a go-forward basis.

8. IN-SERVICE ADDITION NET CUMULATIVE ASYMMETRICAL VARIANCE ACCOUNT

In the EB-2014-0238 settlement agreement approved by the Board on November 19, 2014, the parties agreed that HOSSM would establish a net cumulative asymmetrical variance account for the test years to track the impact on revenue requirement of the cost of in-service capital additions during the test years compared to Board approved amounts, for disposition in a future rate application. The purpose of the account is to capture the revenue requirement amount which (i) would arise if the total capital in-service additions forecasted by HOSSM for the test years 2015 and 2016 are higher than the actual total capital in-service additions for 2015 and 2016, and (ii) reflects the net difference between the forecasted in-service additions for 2015 and 2016 in the event that the circumstance set out in (i) occurs. If the cumulative amount of in-service additions during 2015 and 2016 is less than the cumulative Board-approved amount, then the revenue requirement impact of the shortfall would be entered in the variance account.

HOSSM's cumulative in-service additions were less than the Board-approved amount of in-service additions for 2015 and 2016 of $19,228,700, by $927,203. Therefore, HOSSM has recorded a credit balance of $143,935, which is the calculated amount of revenue requirement owed to ratepayers to cover this shortfall.

HOSSM is seeking to disburse the forecast December 31, 2018 credit balance of $148,110, inclusive of carrying charges, as described in Exhibit E, Tab 1, Schedule 3.

Given that the intent of this account has been met and contingent on disbursement of the credit balance, HOSSM proposes to close this account as it will no longer be required in the future.

PLANNED DISPOSITION OF REGULATORY ACCOUNTS

1. PROPOSED METHODOLOGY FOR DISBURSAL

In this application Hydro One Sault Ste. Marie ("HOSSM") is proposing to aggregate all of the deferral and variance account balances that HOSSM is seeking approval for, and disburse the total amount in 2019. This aggregation is consistent with the approach applied in previous applications, and most recently in the Board-Approved Settlement Agreement in proceeding EB-2014-0238[1]. HOSSM is seeking approval to disburse a total credit balance of $94,909 by decreasing its annual revenue requirement for Uniform Transmission Rates ("UTR") in 2019. HOSSM does not intend to seek a true-up to this amount once collection in 2019 is complete.

2. EXISTING DEFERRAL AND VARIANCE ACCOUNT RECOVERY

HOSSM is currently collecting a deferral account balance from ratepayers over a three year period (account 1595) resulting from the Board-Approved Settlement Agreement related to EB-2014-0238. This 3-year collection was scheduled to be completed as of December 31, 2017, however HOSSM continues to record ongoing collection of this deferral account balance in 2018 (as the collection remained in their UTR for 2018). The forecasted December 31, 2018 credit balance of this account is $1,017,727. This is made up of a credit balance of $1,115,593 related to the aggregate asset amounts, offset in part by a debit balance of $97,866 related to the IFRS-CGAAP Transitional PP&E account which draws carrying charges at a different rate and thus is accounted for separately. HOSSM is not seeking approval to disburse this balance as a part of this application as

---

[1] EB-2014-0238 - Great Lakes Power Transmission Rate Application for 2015 and 2016.

collection remains ongoing in 2018 and it would be most prudent to wait for the year to conclude and financial statements audited before determining the final amount to be refunded. HOSSM will disburse this balance, inclusive of carrying charges in a future rate application.

3. NEW DEFERRAL ACCOUNT DISBURSALS

The subsections below deal with the individual accounts and sub-accounts that HOSSM is proposing to disburse in this application. Section 4.0 below deals with the aggregation of the accounts, the treatment of carrying charges, and the proposed disbursal methodology.

3.1 ACCOUNT 1508 – SUB-ACCOUNT COMSTOCK CLAIM

As illustrated in Table 1, HOSSM is forecasting a debit balance of $99,338 in this sub-account at December 31, 2018, inclusive of carrying charges. HOSSM is seeking approval to disburse this balance as a part of this application.

Table 1 - Account 1508 – Comstock Claims

Year	Opening Balance	Costs Incurred	Transfers	Cumulative Costs	Carrying Charges	Transfers	Cumulative Carrying Charges	Closing Account Balance
2010	$0	$1,660,623	$0	$1,660,623	$0	$0	$0	$1,660,623
2011	1,660,623	106,634	-	1,767,257	24,920	-	24,920	1,792,177
2012	1,792,177	375,800	-	2,143,057	27,855	-	52,775	2,195,833
2013	2,195,833	93,664	-	2,236,721	31,928	-	84,704	2,321,425
2014	2,321,425	80,404	-	2,317,126	33,055	-	117,759	2,434,884
2015	2,434,884	15,075	(2,261,466)	70,735	789	(92,839)	25,709	96,444
2016	96,444	-	-	70,735	778	-	26,487	97,222
2017	97,222	-	-	70,735	849	-	27,336	98,071
2018	98,071	-	-	70,735	1,268	-	28,604	99,338
				$70,735			**$28,604**	**$99,338**

3.2 ACCOUNT 1508 – SUB-ACCOUNT PROPERTY TAX AND USE AND OCCUPATION PERMIT FEE VARIANCES

As illustrated in Table 2, HOSSM is forecasting a debit balance of $17,974 in this sub-account at December 31, 2018, inclusive of carrying charges. HOSSM is seeking approval to disburse this balance as a part of this application.

Table 2 - Account 1508 - Property Tax

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2016	$0	$17,367	$17,367	$88	$88	$17,454
2017	17,454	-	17,367	208	296	17,663
2018	17,663	-	17,367	311	607	17,974
			$17,367		**$607**	**$17,974**

3.3 ACCOUNT 1508 – SUB-ACCOUNT BES DEFINITIONAL CHANGE

As illustrated in Table 3, HOSSM is forecasting a debit balance of $20,755 in this sub-account at December 31, 2018, inclusive of carrying charges. HOSSM is seeking approval to disburse this balance as a part of this application.

Table 3 - Account 1508 - BES Definitional

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2013	$0	$6,928	$6,928	$33	$33	$6,961
2014	6,961	12,627	19,555	133	166	19,721
2015	19,721	-	19,555	233	399	19,955
2016	19,955	-	19,555	215	615	20,170
2017	20,170		19,555	235	850	20,405
2018	20,405		19,555	351	1,200	20,755
			$19,555		**$1,200**	**$20,755**

3.4 ACCOUNT 1508 – SUB-ACCOUNT OEB COST ASSESSMENT VARIANCES

As illustrated in Table 4, HOSSM is forecasting a credit balance of $84,866 in this sub-account at December 31, 2018, inclusive of carrying charges. HOSSM is seeking approval to disburse this balance as a part of this application.

Table 4 - Account 1508 - OEB Cost Assessments

Year	Opening Balance	Costs Incurred	Cumulative Costs	Carrying Charges	Cumulative Carrying Charges	Closing Account Balance
2016	$0	($32,776)	($32,776)	($120)	($120)	($32,896)
2017	(32,896)	(49,806)	(82,582)	(685)	(805)	($83,386)
2018	(83,386)	-	(82,582)	(1,480)	(2,285)	($84,866)
			($82,582)		**($2,285)**	**($84,866)**

4. AGGREGATION OF ACCOUNTS

Table 5 demonstrates the balances of the deferral and variance accounts that HOSSM is seeking to disburse entirely in 2019. Positive amounts in the table are debit amounts that are recoverable by HOSSM, while negative amounts in the table are credit amounts that are payable by HOSSM.

Table 5- Deferral and Variance Account Balances

Account Number	Account Description	Dec 31, 2018 Balance Sought for Disbursal
1508	Cumulative Asymmetrical Variance	(148,110)
1508	OEB Cost Assessment Variances	(84,866)
1508	Legal Claim (Comstock)	99,338
1508	Property Tax Variances	17,974
1508	BES	20,755
	Total Deferral Accounts	**(94,909)**

For all accounts being disbursed, carrying charges are calculated, consistent with the Board's direction and principals, using the OEB's issued prescribed accounting interest rates applicable to the carrying charges of deferral and variance accounts.

Subject to the Board's approval, HOSSM is seeking to disburse the aggregate credit balance of $94,909 by decreasing its 2019 revenue requirement, that is in turn, used by the Board in the calculation of UTR.

CONTINUITY SCHEDULE REGULATORY ACCOUNTS

The tables below demonstrate the continuity of Hydro One Sault Ste. Marie's ("HOSSM")'s deferral and variance accounts for 2014, 2015, 2016 and 2017 actual, as well as 2018 forecast. The continuity schedules do not include any amounts accrued or forecasted to be accrued in the International Financial Reporting Standards ("IFRS") Gains and Losses deferral account, as any amounts accrued since 2015 will not be disbursed during the 10 year deferral period, and no additional amounts will be accrued in these accounts throughout the life of the deferral period.

Table 1 - Continuity of Deferral and Variance Accounts - 2014

Account Number	Description	Opening Principle as of Jan 1, 2014	Transactions in 2014	Dispositions in 2014	Transfers in 2014	Closing Principle as of Dec 31, 2014	Opening Interest as of Jan 1, 2014	Interest for 2014	Dispositions in 2014	Transfers in 2014	Closing Interest as of Dec 31, 2014	Account Balance at Dec 31, 2014
		2014										
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	EWT Support Costs	54,972	-	-	-	54,972	1,187	808	-	-	1,995	56,967
1508	Legal Claim (Comstock)	2,236,721	80,404	-	-	2,317,126	84,704	33,055	-	-	117,759	2,434,884
1508	Property Tax Variances	-	-	-	-	-	-	-	-	-	-	-
1508	EWT Variance	274,963	169,235	-	-	444,198	1,091	5,868	-	-	6,959	451,157
1508	BES	6,928	12,627	-	-	19,555	33	133	-	-	166	19,721
1508	IFRS Gains and Losses	452,924	214,964	-	-	667,888	966	(966)	-	-	-	667,888
1592	Changes in Tax Legislation	-	-	-	-	-	-	-	-	-	-	-
1575	IFRS-CGAAP Transitional PP&E Amounts	-	(433,945)	-	-	(433,945)	-	-	-	-	-	(433,945)
1595	Aggregate Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-
	Subtotal Regulatory Assets	**$3,026,509**	**$43,286**	**$0**	**$0**	**$3,069,794**	**$87,981**	**$38,898**	**$0**	**$0**	**$126,879**	**$3,196,673**
Regulatory Liabilities:												
1595	Three Year Liability Amount	(1,115,343)	-	784,511	-	(330,832)	(321,735)	(11,086)	-	-	(332,821)	(663,653)
	Subtotal Regulatory Liabilities	**($1,115,343)**	**$0**	**$784,511**	**$0**	**($330,832)**	**($321,735)**	**($11,086)**	**$0**	**$0**	**($332,821)**	**($663,653)**
	Net Regulatory Asset (Liability) Balance	**$1,911,166**	**$43,286**	**$784,511**	**$0**	**$2,738,962**	**($233,754)**	**$27,812**	**$0**	**$0**	**($205,942)**	**$2,533,021**

Table 2 - Continuity of Deferral and Variance Accounts - 2015

Account Number	Description	2015 Opening Principle as of Jan 1, 2015	Transactions in 2015	Dispositions in 2015	Transfers in 2015	Closing Principle as of Dec 31, 2015	Opening Interest as of Jan 1, 2015	Interest for 2015	Dispositions in 2015	Transfers in 2015	Closing Interest as of Dec 31, 2015	Account Balance at Dec 31, 2015
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	EWT Support Costs	54,972	-	-	(54,972)	-	1,995	-	-	(1,995)	-	-
1508	Legal Claim (Comstock)	2,317,126	15,075	-	(2,261,466)	70,735	117,759	789	-	(92,839)	25,709	96,444
1508	Property Tax Variances	-	-	-	-	-	-	-	-	-	-	-
1508	EWT Variance	444,198	-	-	(444,198)	-	6,959	-	-	(6,959)	-	-
1508	BES	19,555	-	-	-	19,555	166	233	-	-	399	19,955
1508	IFRS Gains and Losses	667,888	-	-	(667,888)	-	-	-	-	-	-	-
1592	Changes in Tax Legislation	-	-	-	-	-	-	-	-	-	-	-
1595	IFRS-CGAAP Transitional PP&E Amounts	(433,945)	-	143,298	-	(290,647)	-	(28,141)			(28,141)	(318,788)
1595	Aggregate Regulatory Asset - 2015	-	-	(924,545)	3,097,693	2,173,148	-	29,492	-	(231,028)	(201,536)	1,971,612
	Subtotal Regulatory Assets	**$3,069,794**	**$15,075**	**($781,247)**	**($330,832)**	**$1,972,791**	**$126,879**	**$2,374**	**$0**	**($332,821)**	**($203,568)**	**$1,769,223**
Regulatory Liabilities:												
1595	Three Year Liability Amount	(330,832)	-	-	330,832	-	(332,821)	-	-	332,821	-	-
	Subtotal Regulatory Liabilities	**($330,832)**	**$0**	**$0**	**$330,832**	**$0**	**($332,821)**	**$0**	**$0**	**$332,821**	**$0**	**$0**
	Net Regulatory Asset (Liability) Balance	**$2,738,962**	**$15,075**	**($781,247)**	**$0**	**$1,972,791**	**($205,942)**	**$2,374**	**$0**	**$0**	**($203,568)**	**$1,769,223**

Table 3 - Continuity of Deferral and Variance Accounts - 2016

2016												
Account Number	**Description**	**Opening Principle as of Jan 1, 2016**	**Transactions in 2016**	**Dispositions in 2016**	**Transfers in 2016**	**Closing Principle as of Dec 31, 2016**	**Opening Interest as of Jan 1, 2016**	**Interest for 2016**	**Dispositions in 2016**	**Transfers in 2016**	**Closing Interest as of Dec 31, 2016**	**Account Balance at Dec 31, 2016**
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	Cumulative Asymmetrical Variance	-	-	-	-	-	-	-	-	-	-	-
1508	OEB Cost Assessment Variances	-	(32,776)	-	-	(32,776)	-	(120)	-	-	(120)	(32,896)
1508	EWT Support Costs	-	-	-	-	-	-	-	-	-	-	-
1508	Legal Claim (Comstock)	70,735	-	-	-	70,735	25,709	778	-	-	26,487	97,222
1508	Property Tax Variances	-	17,367	-	-	17,367	-	88	-	-	88	17,454
1508	EWT Variance	-	-	-	-	-	-	-	-	-	-	-
1508	BES	19,555	-	-	-	19,555	399	215	-	-	615	20,170
1508	IFRS Gains and Losses	-	-	-	-	-	-	-	-	-	-	-
1592	Changes in Tax Legislation	-	-	-	-	-	-	-	-	-	-	-
1575	IFRS-CGAAP Transitional PP&E Amounts	(290,647)	-	143,359	-	(147,288)	(28,141)	(17,098)	-	-	(45,239)	(192,527)
1595	Aggregate Regulatory Asset - 2016	2,173,148	-	(924,155)	-	1,248,993	(201,536)	16,827	-	-	(184,709)	1,064,284
	Subtotal Regulatory Assets	**$1,972,791**	**($15,409)**	**($780,796)**	**$0**	**$1,176,586**	**($203,568)**	**$689**	**$0**	**$0**	**($202,879)**	**$ 973,707**
	Net Regulatory Asset (Liability) Balance	**$1,972,791**	**($15,409)**	**($780,796)**	**$0**	**$1,176,586**	**($203,568)**	**$689**	**$0**	**$0**	**($202,879)**	**$973,707**

Table 4 - Continuity of Deferral and Variance Accounts - 2017

Account Number	Description	2017 Opening Principle as of Jan 1, 2017	Transactions in 2017	Dispositions in 2017	Transfers in 2017	Closing Principle as of Dec 31, 2017	Opening Interest as of Jan 1, 2017	Interest for 2017	Dispositions in 2017	Transfers in 2017	Closing Interest as of Dec 31, 2017	Account Balance at Dec 31, 2017
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	Cumulative Asymmetrical Variance	-	(143,935)	-	-	(143,935)	-	(1,595)	-	-	(1,595)	(145,530)
1508	OEB Cost Assessment Variances	(32,776)	(49,806)	-	-	(82,582)	(120)	(685)	-	-	(805)	(83,386)
1508	Legal Claim (Comstock)	70,735	-	-	-	70,735	26,487	849	-	-	27,336	98,071
1508	Property Tax Variances	17,367	-	-	-	17,367	88	208	-	-	296	17,663
1508	BES	19,555	-	-	-	19,555	615	235	-	-	849	20,404
1508	IFRS Gains and Losses	-	-	-	-	-	-		-	-	-	-
1592	Changes in Tax Legislation	-	-	-	-	-	-		-	-	-	-
1575	IFRS-CGAAP Transitional PP&E Amounts	(147,288)	-	147,288	-	-	(45,239)	(6,476)	-	-	(51,715)	(51,715)
1595	Aggregate Regulatory Asset - 2017	1,248,993	-	(1,248,993)	-	-	(184,709)	7,200	-	-	(177,509)	(177,509)
	Subtotal Regulatory Assets	**$1,176,586**	**($193,741)**	**($1,101,705)**	**$0**	**($118,860)**	**($202,879)**	**($264)**	**$0**	**$0**	**($203,143)**	**($322,003)**
	Net Regulatory Asset (Liability) Balance	**$1,176,586**	**($193,741)**	**($1,101,705)**	**$0**	**($118,860)**	**($202,879)**	**($264)**	**$0**	**$0**	**($203,143)**	**($322,003)**

Table 5 - Continuity of Deferral and Variance Accounts - 2018

Account Number	Description	2018 Opening Principle as of Jan 1, 2018	Forecast Transactions in 2018	Forecast Dispositions in 2018	Forecast Transfers in 2018	Forecast Closing Principle as of Dec 31, 2018	Opening Interest as of Jan 1, 2018	Forecast Interest for 2018	Forecast Dispositions in 2018	Forecast Transfers in 2018	Forecast Closing Interest as of Dec 31, 2018	Forecast Account Balance at Dec 31, 2018
Regulatory Assets:												
1508	Green Energy Deferral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1508	Cumulative Asymmetrical Variance	(143,935)	-	-	-	(143,935)	(1,595)	(2,580)	-	-	(4,175)	(148,110)
1508	OEB Cost Assessment Variances	(82,582)	-	-	-	(82,582)	(805)	(1,480)	-	-	(2,285)	(84,866)
1508	Legal Claim (Comstock)	70,735	-	-	-	70,735	27,336	1,268	-	-	28,604	99,338
1508	Property Tax Variances	17,367	-	-	-	17,367	296	311	-	-	607	17,974
1508	BES	19,555	-	-	-	19,555	849	351	-	-	1,200	20,755
1508	IFRS Gains and Losses	-	-	-	-	-	-	-	-	-	-	-
1592	Changes in Tax Legislation	-	-	-	-	-	-	-	-	-	-	-
1595	IFRS-CGAAP Transitional PP&E Amounts	-	-	145,345	-	145,345	(51,715)	4,236	-	-	(47,479)	97,866
1595	Aggregate Regulatory Asset - 2017	-	-	(932,712)	-	(932,712)	(177,509)	(5,372)	-	-	(182,881)	(1,115,593)
	Subtotal Regulatory Assets	**($118,860)**	**$0**	**$ (787,367)**	**$0**	**($906,227)**	**($203,143)**	**($3,266)**	**$0**	**$0**	**($206,409)**	**($1,112,636)**
	Net Regulatory Asset (Liability) Balance	**($118,860)**	**$0**	**($787,367)**	**$0**	**($906,227)**	**($203,143)**	**($3,266)**	**$0**	**$0**	**($206,409)**	**($1,112,636)**