McCarthy Tétrault LLP
PO Box 48, Suite 5300
Toronto-Dominion Bank Tower
Toronto ON M5K 1E6
Canada
Tel: 416-362-1812
Fax: 416-868-0673

Gordon M. Nettleton
Partner
Email: gnettleton@mccarthy.ca

mccarthy tetrault

November 10, 2016

VIA RESS AND COURIER

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

Dear Ms. Walli:

RE: EB-2016-0160 Hydro One Networks Inc. ("Hydro One") Transmission Rates Application – Additional Evidence

The Ontario Energy Board ("**Board**") released its Decision on Motions for Full and Adequate Responses to Interrogatories and Technical Conference Questions on November 1, 2016 (the "**Motions Decision**").

For the purpose of compliance with the Board's findings in the Motions Decision, Hydro One files the attached Additional Evidence, with the exception of the internal audit reports requested, which have been filed under separate cover on November 10, 2016.

Yours truly,

McCarthy Tétrault LLP
Per:

for: Gordon M. Nettleton
GMN

IN THE MATTER OF a cost of service application made by Hydro One Networks Inc. ("**Hydro One**") Transmission with the Ontario Energy Board (OEB) on May 31, 2016 under section 78 of the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2017 and January 1, 2018 ("**Transmission Rate Application**");

AND IN THE MATTER OF the Ontario Energy Board's Decision on Motions for Full and Adequate Responses to Interrogatories and Technical Conference Questions issued in respect of proceeding EB-2016-0160 on November 1, 2016 (the "**Motions Decision**").

HYDRO ONE NETWORKS INC.

ADDITIONAL EVIDENCE

I. INTRODUCTION

Q.1 What is the purpose of this evidence?

A.1 This evidence complies with the directions set out in the Ontario Energy Board ("**OEB**" or "**Board**") Motions Decision dated November 1, 2016. Five matters are addressed:

- NATF Peer Review and Transmission Reliability Report Summaries;
- Business Plans;
- Asset Investment Economic Analysis;
- Internal Audit Reports; and
- Transmission Losses Discussion.

Additionally, in accordance with the Motions Decision, Hydro One will provide its 3rd quarter ROE information in a separate filing, as soon as reasonably practicable after the information becomes publicly available.

II. NATF PEER REVIEW AND TRANSMISSION RELIABILITY REPORT SUMMARIES

Q.2 Please summarize the Motions Decision regarding the NATF Information.

A.2 The Board ordered production of a summaries of the Peer Review and the Transmission Reliability Reports, which includes: (1) data from Hydro One's operations relating to the benchmarks that NATF used to conduct its peer review and transmission reliability assessments in each of the years 2006 to 2015; (2) the total number of members in NATF in each year against which Hydro One was benchmarked; and (3) for each benchmark used in each report, Hydro One's ranking amongst the other transmitters. The stated purpose of obtaining this information is to "help the OEB better understand the transmission system benchmarks that are considered by the industry to be appropriate and Hydro One's year-over-year performance in relation to those benchmarks."[1]

Q.3 Is the NATF Peer Review Report a benchmarking study (i.e. one which uses industry transmission system benchmarks and Hydro One's related performance)?

A.3 No. The NATF Peer Review Report considers detailed operational practices and processes for transmission. Hydro One's professional peers observe and assess Hydro One's operational practices and processes, and provide advice on how they may be modified to promote continuous improvement. The peer review process and advice given is not based on quantitative assessment of Hydro One's performance as against specific, uniform industry metrics. Rather, assessments and resulting advice are based on the experience of the peers.

Q.4 Please describe the NATF Peer Review exercise and the type of content found in the Peer Review Report.

A.4 The exercise involved nine separate teams of reviewers. Each team considered a specific operating practice and detailed work processes for that practice. The operating practices reviewed were: (1) Performance Improvement – Human Performance; (2) Performance Improvement – Operating Experience; (3) Security – Physical; (4) Risk,

---

[1] EB-2016-0160, Decision on Motions for Full and Adequate Responses to Interrogatories and Technical Conference Questions (1 November 2016), p 6 [**Motions Decision**].

Controls & Compliance; (5) System Protection; (6) System Operations; (7) Operator Training; (8) Vegetation Management; and (9) Security – Cyber. Process observations and assessments made by each team are described in the Peer Review Report as "strengths", "noteworthy positives", and proposed recommendations.

A summary of all peer review "strengths identified", "noteworthy positives", and "recommendations" is attached as **Schedule A**, with one exception. The observations and assessments of the cyber-security process have not been included, as dissemination of this information could potentially harm Hydro One's ongoing operational security needs.

Q.5 Please summarize the Transmission Reliability Reports.

A.5 Hydro One first became a member of NATF in 2006. Commencing in 2008, Hydro One was invited to annually submit transmission outage data for inclusion in the NATF Transmission Reliability Report. NATF requires all participants in the Transmission Reliability Report to submit five calendar years of data before the participant's data is included in the annual Transmission Reliability Report. This requirement has meant that the first Reliability Transmission Report that included Hydro One was 2012.

Data provided to NATF for 2008-2015 is attached as **Schedule B**. Attached as **Schedule C** is a Transmission Reliability Report summary for the years 2012-2015. The number of peer group participants for each reporting year, the metrics included, and quartile rankings of Hydro One amongst the peer group participants for each metric and in each reporting year are shown.

III. BUSINESS PLANS

Q.6 Please summarize the Motions Decision regarding the Business Plans.

A.6 The Motions Decision requires Hydro One to either provide a business level plan similar to documents provided to Hydro One's Board of Directors and filed with the OEB in the past, or to provide any existing documents that articulate the objectives and high level plans of the most significant business units within Hydro One which would typically be presented to senior management for approval.[2]

Q.7 Will you be providing a business level plan?

A.7 No. As indicated in Hydro One's response to Consumers' Council of Canada IR #6[3], Hydro One's strategic planning process is not yet complete. Similarly, as noted by Mr. Hubert at the Technical Conference in this proceeding, Hydro One does not have a completed business plan.[4] As such, neither a new strategic plan nor a current business plan is in place to be filed.

Q.8 Why are these two plans not complete?

A.8 In 2015, Hydro One was in the process of preparing a business plan similar to what has been filed in previous applications. Beginning in May 2015, components of the drafted plan were reviewed by management in the normal course. In July 2015, significant changes occurred which affected the plan:

- Effective July 1, 2015, Hydro One appointed its new Chief Financial Officer;
- On July 17, 2015, a new Board of Directors was appointed; and
- Effective September 3, 2015, Hydro One appointed a new Chief Executive Officer.

In light of these significant changes, the proposed business plan was reviewed and challenged by the new senior management. In November 2015, formal discussion of the draft plan occurred between management and the Board of Directors.

Following this discussion, and recalling that Hydro One had at that time only recently completed its Initial Public Offering ("**IPO**"), the Board of Directors and management agreed that rather than having the Board of Directors approve the draft business plan, management would instead undertake a detailed and exhaustive review of all aspects of the organization. This was done to enable and assess whether the business plans, and

[2] Motions Decision, p 6.
[3] EB-2016-0160, Exhibit I, Tab 13, Schedule 6, Page 1 of 1.
[4] EB-2016-0160, Technical Conference Transcript, Day 2, Page 148, Lines 7-8.

the related, then-upcoming Transmission Rate Application, appropriately and sufficiently reflected the business priorities set by management and agreed by the Board of Directors. These priorities were:

- Focus on customers;
- Reduce the costs of maintaining the electricity system reliability;
- Achieve an injury free workplace;
- Comply with regulatory and reliability standards; and
- Exercise environmental stewardship.

In addition, the new management and the Board of Directors needed to ensure that the projects and activities in the business plan supported the OEB's *Renewed Regulatory Framework for Electricity* ("**RRFE**"), as the Board of Directors and new management considered it critical that the Transmission filing to be submitted in May was consistent with the RRFE.

Q.9 Please describe the review that was undertaken by management and the Board of Directors prior to filing this application.

A.9 Beginning in December 2015, and concluding in May 2016, Hydro One made significant efforts to prepare the Application. This was an extensive process involving review by management of Hydro One's operations and plans, covering such areas as asset management, capital delivery, and operations & maintenance efficiency. This process included a detailed review of the RRFE and focus upon those principles occurred. A customer engagement process to identify customer needs and preferences for purposes of the asset investment plan was developed.[5] Other internal review processes occurred consistent with the RRFE.

Throughout this process, the Board of Directors held meetings with management to be informed of the status of the overall review being undertaken, as well as preparation of

[5] Similarly, the Transmission Cost Benchmarking Study at Attachment 1 of Exhibit B2-2-1, and summarized in the response to Board Staff IR#104, was completed and the recommendations are reflected in the filed Transmission Rate Application: EB-2016-0160, Exhibit B2, Tab 2, Schedule 1, Attachment 1; EB-2016-0160, Exhibit I, Tab 1, Schedule 104.

the final Transmission Rate Application. The memorandum to the Board of Directors respecting the application was provided in Hydro One's response to School Energy Coalition ("**SEC**") IR #001.[6]

Overall, the amount of time, effort and resources Hydro One expended in preparing the Application was equivalent to, if not greater than, those processes used previously in preparing a more traditional business plan.

Q.10 Should the Board be concerned that Hydro One does not have a formalized Business Plan?

A.10 No. The Transmission Rate Application filed by Hydro One contains all the requisite elements, and hence functions as the Transmission Business Plan. As described above, the process undertaken by management and the Board of Directors in filing this Application was extensive. Although there has been no "formal" business plan filed with the Board, Hydro One's management and Board of Directors spent considerable time and effort in a business planning exercise. The result of this exercise is the Transmission Application which serves as Hydro One's business plan and which reflects the outcomes of this planning process. The objectives and high level plans of Hydro One Transmission's business units are all provided in the application in detail.

In the OEB's *Handbook to Utility Rate Applications*, what should be included in a business plan is described:

> "This includes the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the application and the plan to meet them. The OEB expects the business plan to be informed by the utility's engagement with customers. The business plan is supplemented and supported by the associated plans, reports and documentation (including system plans, capital and operational plans, programs, benchmarking, external reviews, and customer engagement activities) which form the core of the rate application. This utility business plan may differ from the corporate business plan that may include matters that go beyond the scope of the OEB's review in a rate application."[7]

All of this information has been provided in the application now before the Board. The intensive work that was completed by management and the Board was necessary. As

[6] EB-2016-0160, Exhibit I, Tab 6, Schedule 1, Attachment 1.

[7] Handbook for Utility Rate Applications, issued by the Ontario Energy Board (13 October 2016), p 6.

discussed, the outcomes of this work include a plan for Transmission that is responsive to the RRFE and to customer needs and preferences.

Q.11 Please provide specific references as to where these elements are addressed in the application.

A.11 Hydro One's strategic goals, values and objectives are summarized at pages 2-4 of Exhibit A-3-1, and further described at Exhibit B1-1-2.[8]

These were also described by Mr. Mayo Schmidt, Hydro One's President and CEO, at pages 3-7 of the September 8, 2016 presentation to the Board panel entitled "2017-2018 Transmission Rate Application". In this presentation, Mr. Schmidt provided a strategic overview which included Hydro One's Vision, Key Outcomes and corresponding RRFE Principles, customer input, success factors that will deliver improved value for ratepayers and shareholders. This presentation has been filed on the record of this proceeding.[9]

Hydro One's customer engagement activities are summarized at pages 4-5 of Exhibit A-3-1 and described in detail at Exhibit B1-2-2.[10] Specific adjustments to the investment plan resulting from the customer engagement process were documented in Hydro One's responses to Building Owners and Managers Association IR#36 and SEC IR #17.[11]

Hydro One's capital expenditure plans and associated need and justification are detailed in its Transmission System Plan summarized at pages 10-13 of Exhibit A-3-1 and further described at Tabs 1 through 4 of Exhibit B1.[12]

Hydro One's operations, maintenance and administrative expense plans and associated need and justification are summarized at pages 18-20 of Exhibit A-3-1 and further described at Tabs 1 through 3 of Exhibit C1.[13]

Extensive external review and benchmarking evidence has been provided in the application:

---

[8] EB-2016-0160, Exhibit A, Tab 3, Schedule 1, Pages 2-4; EB-2016-0160, Exhibit B1, Tab 1, Schedule 2.
[9] EB-2016-0160, RESS File entitled HONI_TxAppPres_20160908, filed on September 8, 2016.
[10] EB-2016-0160, Exhibit A, Tab 3, Schedule 1, Pages 4-5; EB-2016-0160, Exhibit B1, Tab 2, Schedule 2.
[11] EB-2016-0160, Exhibit I, Tab 2, Schedule 36; EB-2016-0160, Exhibit I, Tab 6, Schedule 17.
[12] EB-2016-0160, Exhibit A, Tab 3, Schedule 1, Pages 10-13; EB-2016-0160, Exhibit B1, Tabs 1-4.
[13] EB-2016-0160, Exhibit A, Tab 3, Schedule 1, Pages 18-20; EB-2016-0160, Exhibit C1, Tabs 1-3.

- The Navigant/First Quartile Total Cost Benchmarking Study agreed to as part of the EB-2014-0140 Settlement Agreement is located in Attachment 1 of Exhibit B2-2-1.[14] Hydro One addresses the recommendations from this study in its response to Board Staff IR #104.[15]

- Attachment 1 of Hydro One's response to SEC IR #57 provides the Hugessen Consulting Preliminary CEO/CFO Pay Benchmarking Report. The response also includes a summary of the Towers Watson Hydro One: Executive Compensation Benchmarking Report at Attachment 2, and a summary of the Towers Watson Hydro One Non-Executive Compensation Benchmarking Report at Attachment 3.[16]

- As noted at pages 15-18 of Exhibit A-3-1, Hydro One's new executive leadership and Board of Directors are committed to building a stronger performance management culture, focused on achieving excellence in execution in all aspects of the company's work with the ability to measure and track performance. This Exhibit summarizes the development of a scorecard and the selection of key performance indicators that will measure the drivers of company performance and track productivity improvements.[17] Exhibit B2-1-1 and its Attachments 1-2 further describe the development of the scorecard and key performance indicators.[18]

In summary, Hydro One believes the material referenced in the above Exhibits complies with the information the Board has described in its *Handbook to Utility Rate Applications* respecting business plans.

[14] EB-2016-0160, Exhibit B1, Tab 2, Schedule 1, Attachment 1.
[15] EB-2016-0160, Exhibit I, Tab 1, Schedule 104.
[16] EB-2016-0160, Exhibit I, Tab 6, Schedule 57, Attachments 1-3.
[17] EB-2016-0160, Exhibit A, Tab 3, Schedule 1, Pages 15-18.
[18] EB-2016-0160, Exhibit B2, Tab 1, Schedule 1; EB-2016-0160, Exhibit B2, Tab 1, Schedule 1, Attachments 1-2.

IV. ASSET INVESTMENT ECONOMIC ANALYSIS

Q.12 Please summarize the Motions Decision regarding the Asset Investment Economic Analysis.

A.12 The Motions Decision requires Hydro One to file the "replace versus refurbish" economic analysis and any other documentation that was produced or used in support of the approvals related to three examples for each major asset type. For each major asset type, the three examples will consist of recent projects having the largest investment levels.

Q.13 Please summarize Hydro One's major asset types that use "replace versus refurbish" economic analysis.

A.13 As explained in Tables 4-6, 15, and 16 of Exhibit B1-3-2, Hydro One has five major sustainment investment categories.[19] "Replace versus refurbish" analysis is used with respect to three of the five major categories: (1) Station Reinvestments; (2) Integrated Station Component Replacements; and (3) Lines Refurbishment Investments.

Within the three sustainment investment categories noted above, there are three major asset types that may be subject to a "replace versus refurbish" analysis: (1) Transformers; (2) Breakers; and (3) Lines.

Q.14 Why is a "replace versus refurbish" economic analysis not used with all asset types within an investment category?

A.14 Refurbishment is not always a viable option. Refurbishment is dependent upon the nature and type of asset in question. For example, investment decisions relating to air blast circuit breakers are driven by poor asset performance, obsolescence, reliability concerns and continued asset operation leading to higher maintenance costs. Refurbishment is not a viable option from the outset in such cases because none of these concerns would be addressed through refurbishment. A detailed "replace versus refurbish" economic analysis is therefore not prepared or used.

---

[19] EB-2016-0160, Exhibit B1, Tab 3, Schedule 2, Tables 4-6,15 & 16.

Q.15 Please summarize the Transformer major asset type economic analysis information.

A.15 Four detailed transformer assessment reports that used a "replace versus refurbish" analysis are on the record in this proceeding. These may be found in Attachment 6 of Exhibit I-9-6, "Strachan Transformer Assessment Report, T12", and Attachment 4 of Exhibit TCJ1.33, "Dufferin Transformer Assessment Reports, T1, T3, and T4". Section 7 of these reports describes the "replace versus refurbish" analysis. The Reports also provide condition data, performance and loading history, maintenance records, NPV calculations and recommendations.[20]

Q.16 Are other documents produced or used in support of internal approvals for transformer projects?

A.16 Yes. Business cases are prepared, but only after the investment decision has been made. They are used as part of the work execution process. Please refer to Exhibit TCJ1.33 for a discussion of how business cases are used in this regard.

Business cases for the Strachan and Dufferin projects noted above are currently under development. All of these projects are in the project cost estimation phase. At this point, the business case summaries are not yet finalized, as the release of funds does not occur until the costs estimation and related engineering phase are completed. In view of these circumstances, Hydro One is providing an example of a business case summary document for the Wanstead TS, which is described in Exhibit B1-3-11, Investment Summary Document S17 and attached as **Schedule D**.

Q.17 Please summarize the Breaker major asset type economic analysis information.

A.17 Assessment reports where a "replace versus refurbish" analysis was used in respect of individual circuit breakers are not available, because the "replace versus refurbish" economic analysis is not typically conducted on an individual breaker basis. Instead, circuit breakers are considered as part of an integrated station investment and are included in the overall analysis of that integrated station investment.

[20] EB-2016-0160, Exhibit I, Tab 9, Schedule 6, Attachment 6; EB-2016-0160, Response to Technical Conference Undertaking TCJ1.33, Attachment 4.

Decisions to replace circuit breakers usually occur when circuit breakers are in deteriorated condition, or due to other factors described in Exhibit B1-2-5, refurbishment is not an option.[21] Refurbishment occurs, albeit infrequently, when asset age and conditions warrant to defer replacement. In these circumstances, Hydro One takes into account standard economic analysis charts for the type of circuit breaker involved. Included in Exhibit TCJ1.33 is an Asset Risk Assessment Report and Station Assessment Report for Beck #2 ABCBs. Examples for oil, SF6, and ABCB breakers are enclosed as part of **Schedule E**.

Also included as part of **Schedule E** are three business case summaries relating to the following circuit breakers. These cases underscore the need for upgrades to be made in order to comport with industry standards:

- Beck #2 ABCBs (described in TCJ1.33);
- Barrett Chute (described in Exhibit B1-3-11, Investment Summary Document S21); and
- Martindale TS (described in Exhibit B1-3-11, Investment Summary Document S40).

Q.18 Please summarize the Lines major asset type economic analysis information.

A.18 Lines are the electrical circuits extending between stations. Asset components include line conductors, shield-wire, insulators, hardware, structures and foundations. Only structures and foundations may be refurbished. All other asset components are replaced once they reach end of life condition.

Lines refurbishment investments are driven by conductors reaching an end-of-life condition. Conductor condition is verified by laboratory sample testing. When Lines refurbishment investments are made, the objective is to restore the overall integrity of the electrical circuit. All deteriorated and end-of-life components (i.e. conductor, shield-wire, insulator and hardware) are replaced. Structures and foundations are refurbished or replaced, only as needed.

[21] EB-2016-0160, Exhibit B1, Tab 2, Schedule 5.

A Lines replacement investment concerns the construction and relocation of a new circuit. Line refurbishment (versus replacement) is the preferred option, due to the cost advantage that arises from continued use of the existing transmission corridor and existing structures and foundations. The unit cost to refurbish a Line is approximately $0.48 million per km. In comparison, new line construction unit costs are $1.20 million per km, based on Hydro One's recent project cost experience. The refurbishment unit cost is derived from three refurbishment projects (ISD S67, S71 and S74), as referenced in Hydro One's response to Board Staff IR #86.[22]

Given the magnitude of the unit cost differentials between new line and refurbishment, a "replace versus refurbish" economic analysis is not normally required for Lines projects.

Three conductor sample testing reports verifying end-of-life condition have been attached as **Schedule F**, as well as the business cases prepared for management's approval of the Lines refurbishments.

Q.19 Can you provide information regarding the "replace versus refurbish" analysis used regarding structures and foundations?

A.19 Yes. In Exhibit TCJ2.3, economic analysis of refurbishing a steel structure by applying zinc coating versus replacing the structure was provided.[23] Exhibit I-9-6, Attachment 2: "EPRI Report on Atmospheric Condition Assessments of Hydro One Structures", and Attachment 3: "EPRI Report on Galvatech Coating System Assessment", provide structure population condition assessment and coating product performance data.[24] Hydro One relies on this information to substantiate the proposed structure coating investments described in this Application.

The range of costs for a steel structure replacement is in the magnitude of hundreds of thousands of dollars per structure. Structure coating unit costs range in the tens of thousands of dollars. The economic analysis found in Exhibit TCJ2.3 is representative of other individual steel structure "replace versus refurbish" projects.

[22] EB-2016-0160, Exhibit I, Tab 1, Schedule 86.
[23] EB-2016-0160, Response to Technical Conference Undertaking TCJ2.3.
[24] EB-2016-0160, Exhibit I, Tab 9, Schedule 6, Attachments 2-3.

V. INTERNAL AUDIT REPORTS

Q.20 Please describe the internal audit reports that Hydro One has been required to file.

A.20 The two internal audit reports, entitled "Investment Planning" and "Transmission Lines Preventative Maintenance Optimization" have been filed with the Board under a separate cover letter given the interim confidential status of this information. The cover letter to this separate filing describes Hydro One's reasons for maintenance of the confidential status of these reports.

VI. TRANSMISSION LOSSES DISCUSSION

Q.21 Please summarize the Motion Decision regarding Transmission Losses.

A.21 The Motions Decision requires Hydro One to either provide estimates of transmission losses and their cost, using the approaches described in footnote 9 of Environmental Defence's ("**ED**") Reply Submission dated October 25, 2016,[25] or explain why these estimates cannot be provided or are otherwise inappropriate.

Q.22 Are the estimates of transmission losses and their costs as per ED's Motion Reply inappropriate?

A.22 Yes, for the following reasons. Transmission losses arise as part of the ongoing operation of the integrated power system. Losses associated with each transmission element carrying electrical current ("**Transmission Element**") are determined by the following equations:

$$\textit{Transmission Element Losses} = (\textit{Current})^2 \times \textit{Resistance}$$

The overwhelming majority of Transmission Elements are either: (1) line conductors; or (2) transformers. The summation of all Transmission Element losses equals total transmission system losses:

$$\textit{Transmission System Losses} = \sum \textit{Transmission Element Losses}$$

[25] Motions Decision, p 7; EB-2016-0160, Reply Submission filed by Environmental Defence (25 October 2016), p 3, footnote no. 9.

Q.23 What factors influence the "Current" variable?

A.23 "Current" is a function of many factors, including:

- demand level;
- distribution of that demand;
- dispatch of generation (i.e. source of current);
- grid operation, as directed by the Independent Electric System Operator ("**IESO**");
- scheduled transactions;
- loop flows; and
- customer requirements and restrictions.

Current flow may vary along each Transmission Element in each hour and throughout each year. Current, measured in Amperes (A), is the dominant factor in quantifying losses. Depending on system conditions, Current ranges from 100 A to more than 1000 A for each Transmission Element (typically, the range is around 200-500 A, although it is difficult to make such generalizations).

The dominance of the current variable stems from the square relationship in the equation. For example, a 30% change in Current (e.g. an increase of 30%, from 100 A to 130 A) results in a 69% overall increase in Transmission Element Losses ($130^2 / 100^2 \approx 169\%$).

Overall system demand significantly affects Current flow. The higher the demand, the greater the Current flowing through the system. Distribution of demand across the system also impacts Current flow. The loading profiles at each transmission load centre or transmission customer connection point are determined by the operation patterns and characteristics of load customers.

The location and output levels of generators supplying power to the system determines how much Current will flow across different parts of the transmission system to supply transmission load centres and customers. Transactions (such as exports) and loop flows also result in higher Current flows. Generators located further from load centres result in current flows across a greater number of Transmission Elements for the delivery of energy. Higher losses result when generators are located further away from load centres.

Generation dispatch varies significantly throughout the year between peak, off-peak and shoulder periods. Ontario's IESO directs the day to day operations of the provincial grid. These activities include generation dispatch, transmitter operations, setting voltage levels across the transmission system, and providing ancillary services. Current flows across Transmission Elements, and thus the entire transmission system, are significantly influenced by the IESO's actions, which are essential to ensure the reliable operation of the transmission system as well as electricity market efficiency.

Q.24 Do transmitter operations decisions impact Current flow?

A.24 No. Transmitter operations decisions do not control or affect the level of Current flow in any meaningful way from a Transmission System Losses perspective. The Transmitter may require outages to perform maintenance and repairs, and outages may temporarily change the distribution of current flows. However, all transmission element outages are approved by and under the direction of the IESO. Transmitters' facilities do, however, affect the second variable, "Resistance".

Q.25 Please describe the Resistance variable used in the Transmission Element Losses equation.

A.25 Resistance is a concept analogous to friction. Resistance impedes the flow of Current through a Transmission Element causing some electric energy to be transformed into heat and resulting in losses.

Q.26 Is the quantity of Resistance of line conductors equal to the Resistance with transformers?

A.26 No. In Ontario, the losses that occur on line conductors are more than four times the losses that occur on transformers. Correspondingly, Resistance in aggregate on line conductors is significantly larger than Resistance on transformers.

Q.27 What are the key factors that affect the Resistance of a line conductor?

A.27 There are four such factors:

- Conductor size. The larger the conductor, the lower the Resistance.
- Conductor length. Resistance is directly proportional to the length. For example, (and holding all other variables constant) a typical conductor rating is 0.086 Ohms/km. If the line conductor was 100 km in length, then this Transmission Element would have a Resistance of 8.6 Ohms.
- Conductor temperature. Resistance increases with higher temperatures, which is linked to Current. Higher temperatures are a function of current. The higher the Current level, the higher the temperature (and thus the higher the Resistance).
- Conductor material. Different conductor materials have different Resistance characteristics. Aluminum, particularly aluminum conductor steel reinforced ("**ASCR**"), is the main standard used in North America.

Q.28 Can the inherent Resistance level for a line conductor change once it is placed in operation?

A.28 No. Once line conductors are installed, the Resistance characteristic of that conductor remains constant for the life of the asset, usually for a period ranging between 60 and 80 or more years. Historically, Hydro One has replaced less than 1% of its conductor fleet each year. Going forward, Hydro is projecting a need to replace 1.7% or approximately 500km annually. This means that the Resistance level of 98.3% of Hydro One's conductor fleet would remain unchanged from year to year.

Q.29 Can Resistance improvements occur through oversizing conductors that are replaced annually?

A.29 Annual conductor investments provide only marginal improvements to Resistance. Assuming existing lines and towers can accommodate a larger conductor, Resistance improvements due to a larger conductor typically yields a 10% to 20% reduction in Resistance. Overall cost of the larger conductor, including assessment of whether existing towers and lines could be used for a larger conductor would also require consideration.

Q.30 Please provide an example that illustrates the level of investment needed to materially reduce the Resistance of line conductors.

A.30 Assume Hydro One has a 440 circuit km proposed for conductor replacement in 2018, representing approximately 1.5% of its conductor fleet. Assume also that the overall economic impact of Total System Losses is, as suggested by ED, equal to $390 million given that losses are directly proportional to Resistance (note that this value is given for the purposes of illustration; it is not proven that this is the overall economic impact of Total System Losses).[26] For the purposes of simplicity, also assume that this amount is entirely due to line conductor losses in Ontario.

Under this scenario, the maximum opportunity to reduce losses from the conductor replacement would equal $6 million (i.e. 1.5% of $390 million). However, the maximum opportunity assumes that Resistance could be entirely eliminated, which is not the case. As stated, Resistance improvements range between 10% and 20%, and are due primarily to physical and technological constraints. Assuming a midpoint of 15%, the Resistance improvement opportunity would be valued at $1 million (i.e. 15% x $6 million).

Such incremental reductions in Resistance should be placed in context of the associated costs. A program to increase line conductor sizes would incur costs that far exceed the $1 million benefit level, given the magnitude, scope and length of the line conductors involved. For example, a 440 circuit km conductor replacement would be expected to cost in the range of $180 million.

Resistance improvement through increasing conductor size assumes that all existing towers and other lines components supporting the replaced conductor would have the design capacity to structurally support and allow for the operation of larger conductor.

---

[26] ED's estimate differs significantly from the Total Transmission System Loss-related amounts recovered by the IESO through the wholesale competitive electricity market in 2015 and 2016 to-date. According to the IESO, the Total Transmission System Loss-related amount recovered in 2015 was approximately $66.3 million. For the period January 1 to September 30, 2016, this amount was approximately $36.1 million. Hydro One was advised by the IESO that these amounts were recovered through Charge Code 150 (Net Energy Market Settlement Uplift), which covers differences between the amount paid to suppliers for the commodity and the amount paid by buyers in a given hour. The IESO administers Charge Code 150, not Hydro One.

This is unrealistic given the fact that tower sizes and lines are designed to support the existing in-service conductors, and the opportunities to replace them with a larger conductor are very limited. Overall costs in this illustration would increase dramatically if changes to towers and line design are necessary.

Q.31 Would this analysis change if it was assumed that greater conductor replacement occurred than historical levels?

A.31 Under this scenario, assume Hydro One decided to replace 3% of its conductor fleet. This would mean that 1.5% of that fleet would be replaced before reaching end of life. This outcome alone would impose significant costs that could have been avoided by allowing continued operation of the conductors now in service. The magnitude of those costs would further escalate by inclusion of the full cost of the larger conductor along with additional reinforcements that may be required. It also assumes that resources are available for double the level of conductor replacement work. For 440 circuit km, conductor replacement costs would be expected to be in the range of $180 million. Again, further significant costs would be incurred if changes to towers and lines were also necessary to support the operational design of the new larger conductor. On the benefits side, the Resistance improvement would only increase to approximately $2M (3% x 390M x 15%). The main conclusion from this scenario is that increased levels of conductor replacement for the sole purpose of improving Resistance would result in significant costs with very marginal economic benefits.

Q.32 The illustrations above address Transmission Element Losses. How does this analysis impact Total System Losses?

A.32 Recall the formula for Total System Losses is the summation of all Transmission Element Losses. The summation formula means that Resistance for 98.5% of Hydro One’s remaining Transmission Element Losses would remain unchanged. Any Resistance improvement from a Transmission Element is still muted by the fixed nature of Resistance on all remaining Transmission Element Losses. Again, the far more substantive change shown in this analysis is the significant costs that would be incurred to effectively “chase” a relatively small economic benefit.

Q.33 The illustrations above focus on conductor size. Do any of the other factors that contribute to Resistance provide opportunities for improvements?

A.33 As noted above, the other factors affecting Resistance are conductor length, conductor temperature and conductor material.

Hydro One has little or no opportunity to reduce the length of conductors. In the case of conductor replacements, the length is effectively predetermined by the location of existing rights of way and towers. When new lines are proposed, the shortest route is selected, subject to other physical, technical, environmental and existing land use constraints.

Conductor temperature is a function of Current flow; it is not a variable that Hydro One can manage independently.

With respect to conductor material, ASCR is widely recognized as having the best overall performance and cost balance for most transmission operations. ASCR is a standard that Hydro One uses for most of its line conductors, including annual line conductor replacement.

Q.34 Why does collecting information on Transmission System Losses not inform the identification of candidate transmission investments?

A.34 The Transmission System Losses is an aggregate value, and as explained above is the sum of the losses on all transmission elements. It is largely a reflection of the Current flow that is driven by the operation of market participants other than the Transmitter. Transmission line investments rely on locational and situational specifics and the associated information to assess need, identify solutions and determine the cost-benefit trade-offs. The level of Transmission System Losses as an aggregate value does not assist in determining locational and situational specifics. It does not identify what transmission elements to focus on, nor does it provide an indication that a specific investment is even required.

Q.35 What conclusions arise from this illustration?

A.35 There are two main conclusions:

1. Changes in Transmission System Losses are far more dependent upon Current than on Resistance. Factors that affect Current relate to the overall operation of the electricity market and the activities of other market participants in Ontario, and fall outside of Hydro One's responsibilities. As such, variations of losses on the transmission system would not inform a transmitter's performance, good or bad.

2. Transmission System Losses are not directly factored into Hydro One's investment planning process. This is because the opportunities to make a material reduction to Resistance are extremely limited. Due to the enormity of the costs required to reduce Resistance (and therefore to reduce losses), Transmission System Losses will never form the basis for identifying and selecting an investment candidate except in very special and limited circumstances.

VII. CONCLUSION

Q.36 Does this conclude Hydro One's additional evidence?

A.36 Yes.

SCHEDULE A

See attached summary of recommendations in NATF Peer Review Report for 2016.

Business Operational Area	Objective
1. Performance Improvement - Human Performance	Human Performance Improvement (HPI) program effectively implements processes, training and tools to prevent, detect, and correct human errors that may adversely impact the safe, reliable operation of the bulk electric system.
Strengths Identified	**Noteworthy Items Identified**
> There is a Management Workplace Safety Observation (WSO) process in place > The Operations Control Room has many elements of a Human Success Program (HSP) and they are utilized in day-to-day operations > The Network Management System (NMS) has many HSP attributes built into it > Use of the "Event Learning Opportunity" instead of an “Event Investigation” > Everyone realizes the HSP benefits the entire company	> Use of the name "Human Success Program" > Peer-to-Peer workplace safety observations

Observations	Recommendations
HSP “pilot” has no fully-dedicated resources	Dedicate technology and personnel to the HSP as needed
HSP supported by 3 VPs	The entire Executive Management team needs to understand, believe and communicate the HSP to their groups
Scope of HSP “pilot” is too limited in size	Launch the program in a phased approach; begin "phase one" with the entire Operations Department
HSP is only being looked at as a safety program	The HSP needs to stands alone. (Human Performance is safety, reliability, security, etc.)
HSP “Pilot” team has an inconsistent understanding of what HSP means and what the pilot program entails	Create a common and consistent message of what HSP means
No metrics or milestones to measure effectiveness of the HSP	Develop HSP metrics to measure effectiveness along with a correlating timeline
Components of Human Performance are scattered throughout many parts of the organization	Establish processes under the HSP that are consistent across the company

Business Operational Area	Objective
2. Performance Improvement - Operating Experience	Operating experience is defined as the knowledge and skills gained from events, disturbances, near misses, adverse trends and lessons learned that can be used to prevent further occurrences. Operating experience can be further defined as any transmission (reliability) learning opportunity worth sharing or for potential trending, regardless of actual impact or cause. Operating experience could be positive or negative.
Strengths Identified	**Noteworthy Items Identified**
> Upper management, down through OE staff, includes OE metrics in Performance Contracts for sharing internal and external reports > Expertise and dedication toward a successful OE program at multiple levels of management and staff > Manual review of completed Action Items prior to marking "complete" > Timeline diagram in investigation reports	> Disciplinary action is separated from the formal investigation > Robust overall communication of OE related information to management staff, customers, and NATF > Bilateral sharing of OE events to meet goals

Observations	Recommendations
Asset Event Investigation (AEI) process hinges on a single facilitator to ensure process proceeds to completion.	Develop a succession plan for this role to ensure the continuation of a currently successful process in absence of this facilitator
Gaps in the dissemination of OE program (source and access for event information) down to level of field personnel	Periodically reinforce to all staff the OE Program (high level overview of entire program, tiers, goals, access, and information sources, for OE events). This could be accomplished through corporate newsletter or similar.
"System Event Investigation Operational Policy document" currently remains in draft form	Finalize and approve this draft document to provide the overall formal OE program description and scope
Protection Operations Analysis process does not demonstrate routine communication of status of corrective action plans. Large number of incomplete action items	Initiate automatic status updates, such as utilized by the System Event Investigation (SEI) process in SharePoint

Business Operational Area	**Objective**
3. Security - Physical	To improve reliability and resiliency by improving the security program to effectively monitor and mitigate risks associated with physical security threats.
Strengths Identified	**Noteworthy Items Identified**
> Knowledgeable and engaged Security Operations staff; diverse skill set > Security Operations team demonstrates detailed knowledge around code of practices and regulatory obligations > Thorough and well-documented Physical Security processes and procedures > Tyco technologies well integrated to provide monitoring staff with situational awareness of activities occurring on Hydro One properties > Formalized, documented business continuity and emergency preparedness programs > Demonstrated effort and focus on field testing to show evidence of behaviors and practices that pose a risk to the organization > Implemented and coordinate periodic meetings of internal and external critical infrastructure businesses to discuss potential security vulnerabilities > Security Operations partnering with Toronto Police Services for more effective emergency response	> Robust and effective theft identification and restitution program > Comprehensive approach to identify potential physical security vulnerabilities and threat vectors that pose risk to Hydro One critical transmission stations

Observations	**Recommendations**
No Personal Risk Assessment (PRA) for employees or contractors, except for employees requesting PSP access	Develop and implement a formal risk-based pre-employment background screening program for all new employees and contractors having access to Hydro One assets
Insecure method of access control for transmission stations	Implement security enhancements identified in Physical Security Plan e.g. card reader access
Implement security enhancements identified in Physical Security Plan e.g. card reader access	Document and implement a formal process to ensure individuals have appropriate access based on business need
Unstaffed guard house at Operations Grid Control Center (OGCC)	Perform initial screening of visitors at perimeter of OGCC

Observations	Recommendations
Tyco performs monitoring and logging activities for Hydro One CIP sites and other facilities	Continue evaluation of business case for in-house vs. 3rd party monitoring
Unique security exposures with leased space for corporate headquarters offices	Conduct Physical Security Threat Risk Assessment (PSTRA) for Trinity headquarters building; develop and implement action plan
Lack of appropriate level security / access control to executive level offices	Evaluate access control to executive offices; implement appropriate actions to decrease access and improve safety and security
No formal strategic resource planning and budgeting process that includes Security Operations in planning phase of projects	Develop and implement a formal process to ensure Security Operations is included in the planning phase of projects
No formal training or awareness communication regarding Active Shooter events	Develop and implement "Armed Aggressor" training and security awareness communication program
Security awareness communications developed but no formal onboarding education for new employees and managers	Develop and implement a formal security onboarding education for new hires and new managers

Business Operational Area	**Objective**
4. Risk, Controls & Compliance	To facilitate the development of and assess the maturity of governance, risk assessment, and internal control programs related to transmission reliability, security and compliance.
Strengths Identified	**Noteworthy Items Identified**
> Corporate compliance training provided to all company employees and contractors > Internal controls for the compliance program are well developed and documented > Governance Delegates are required to develop standard-specific training modules to communicate compliance objectives, risks, and controls to applicable staff > Reliability Compliance Assurance maintains the Compliance Scorecard and the Compliance Dashboard, which contain key compliance program information on a monthly basis > Ongoing regulatory tracking of new or modified regulations with a developed program for communication to accountable personnel > Compliance Assurance Tool has workflow management to provide accountability, notification, and escalation of compliance activities	> Policy framework and authority hierarchy ensure program activities are conducted in accordance with objectives and that personnel with oversight authority are clear on roles and responsibilities > Well-developed and documented Process for Reliability Risk Assessment > Directives to Achieve Reliability Compliance (DARCs) hold business units accountable for executing compliance obligations and activities, including evidence requirements

Observations	**Recommendations**
Reliability Compliance Assurance is within the transmission planning organization therefore is not fully independent.	Move Reliability Compliance Assurance into an independent line of reporting or implement a structured set of checks and balances outside the line of business
The Governance Delegate can make the determination whether there is a potential non-compliance without consultation with Reliability Compliance Assurance	Modify the ICP to require that the Governance Delegate obtain and consider the opinion of RCA group in analyzing whether to identify a potential violation
Reliability Compliance Assurance does not verify that the correct evidence was uploaded in the Compliance Assurance Tool prior to Self-Certification	Reliability Compliance Assurance should verify all evidence uploaded to CAT is appropriate to demonstrate compliance prior to Self-Certification
Reliability Standard Readiness is not formally included in the development of all new or revised Directives to Achieve Reliability Compliance (DARCs) for compliance standard	Reliability Standard Readiness should procedurally be included in the DARC Drafting Team or in the review of DARCs for all new or revised standards

Observations	Recommendations
requirements	
The Reliability Risk Assessment (RRA) has only one company-specific risk factor	Incorporate additional company-specific risk factors in the RRA
The Reliability Risk Assessment (RRA) is only reviewed on a three year cycle	Review the RRA at least annually to identify any needed changes and update as needed
Hydro One has not yet conducted an independent assessment of the compliance program implementation and effectiveness	Incorporate periodic independent assessments of the compliance program implementation and effectiveness in the Framework for Reliability Compliance Assurance
The business unit internal controls are less developed than the entity level controls	Continue the development and implementation of the business unit level internal controls framework, including inventory, monitoring, and testing

Business Operational Area	Objective
5. System Protection	To assure that protection systems are installed, designed and maintained to be safe, secure and dependable. Protection systems should coordinate to detect and isolate only the faulted element within a protected zone to ensure a reliable bulk power system.
Strengths Identified	**Noteworthy Items Identified**
> New P&C Engineers are rotated through 3 assignments before being assigned to a permanent position > Relay setting peer review is performed anonymously > Standard design templates have been established for each protection scheme > Continuous updates are made to the Power Systems Database (PSDB) > Very detailed database of fault analysis data is stored in Protection Control Management Information System (PCMIS)	> Most BES stations have redundancy which is utilized in protection and control design > Post commissioning in-service field inspection performed

Observations	Recommendations
Fault location is labor intensive and requires personnel to visit substation to access distance-to-fault info	Enable remote and automatically retrieve fault information for system operations
Relay records to support post-disturbance analysis for naturally occurring event analysis retrieved manually	Utilize available software packages and connectivity to remote relays to facilitate the fault analysis process
There is a backlog of requests for comparisons of "as left" and "as found" settings to database settings	Dedicate resources to alleviate backlog
Relay access ports were found to not be sealed	Any access ports not internally disabled should have tamper detection devices installed
Relay settings are not in the Computer Aided Protection Engineering (CAPE) program	Add all relay settings to CAPE to fully utilize program and meet future NERC standard
Some design standards installed have been found to contain errors	Perform a peer review within standards group and test all standards prior to implementing
Protection advisories and lessons learned are not shared throughout all the P&C departments	Assemble a team to share information comprised of members who create standards, perform fault analysis, design, create settings and install/maintain protection systems

Business Operational Area	Objective
6. System Operations	To identify and promote superior practices in the tools, control room environment and the operating practices and procedures that are used in ensuring a reliable bulk power system.
Strengths Identified	**Noteworthy Items Identified**
> Watchdog Application actively monitors the health of key Network Management System (NMS) applications > OGCC back-up generators are from different manufacturers > NMS Displays and Controller Reliability Tools-Station Navigation	> NMS Displays and Controller Reliability Tools > Significant forethought in succession planning provides for very knowledgeable Controllers > Shift Control Engineer/Officer is on staff 24x7 in the control room

Observations	Recommendations
Switching order process is a manual, paper based process	Complete automation of processes through the Network Outage Management System & Mobile-2-Mobile projects
NMS is configured to generate audible tones for every alarm that occurs	Implement alarm functionality to enable configurable alarms
Video wall display content does not optimize Controller's Situational Awareness	Perform analysis of information presented to Controllers to improve Situational Awareness
NMS restricts the operator to a single alarm list display without any ability to filter by voltage level	Add feature to view multiple alarm lists, to filter alarms by voltage level, and incorporate “Intelligent Alarm Processor” technology
Alarm Watchdog Monitor is integrated application in NMS	Develop an external application that is independent of the state of the NMS
Rotating Load Shed (RLS) testing does not cover actual operability to the field devices	Schedule field test of RLS operability from SCADA to control relays in the field
Procedure revision notification relies on email without a solid verification process	Implement SharePoint site for tracking and verification of procedure revision process
No State Estimator / Contingency Analysis performance goals established	Establish and implement performance goals / metrics for network applications
Distance-to-fault information available for limited number of circuits (24)	Complete distance-to-fault information for all circuits
Wireless Priority Service (WPS) is not utilized for emergency communications	Add WPS to critical cell phones identified in Disaster Recovery scenarios

Observations	Recommendations
Business Operational Area	**Objective**
7. Operator Training	The operator training program utilizes a systematic approach that prepares its system operators to competently perform their job tasks; provides sufficient resources, tools, and documentation to effectively and efficiently administer its operator training program; and is reinforced by a culture of operational excellence.
Strengths Identified	**Noteworthy Items Identified**
> Robust simulator training > Controller trainees are used in the training process of newer controller trainees–NERC Certification exam > Initial Controller Training Program includes "Field" training > Training staff acknowledges student feedback > Training department has a dedicated classroom	> "A Day in the Life" simulation training provides excellent realistic training > Very high entry criteria for the Controller Training Program > New controller trainees are hired as a class, which leads to efficient use of training resources > Training department is an integral partner with operations in the hiring process of new controller trainees

Observations	Recommendations
No documented job task analysis (JTA) or task to training matrix	Complete JTA and develop task to training matrix
Training staff is utilized beyond their maximum availability	Assign additional dedicated resources
Responsibility for PER-005-2 & COM-002-4 training requirements not clearly defined	Define training department responsibility for meeting the requirements of these NERC standards
Simulator room has deficiencies (telephone, wall boards)	Implement training telephone environment . Upgrade wallboards
No instructor qualification program in place	Establish program requirements for qualification of instructional staff (NERC Continuing Education Administration Manual)
Training staff not afforded opportunities for professional development	Provide time and opportunities for training staff development
Current record-keeping and training registration process is manual and not integrated and missing dedicated resource for maintaining these records	Implement an integrated training database / Learning Management System (LMS) with dedicated resource to maintain
No process in place to assess retention and application of previously attended training courses	Establish program to assess retention and application of previously attended courses

Observations	Recommendations
Training program documents not reviewed / updated annually	Establish a program to review and update training program documents annually
Student and presenter feedback not consistently shared with management outside of training department	Establish meeting schedule between training and operations departments to share training feedback, concerns, and training needs

Business Operational Area	Objective
8. Vegetation Management	To ensure the vegetation management program effectively maintains rights of way that reduce the risk that vegetation will encroach the Minimum Vegetation Clearance Distances (MVCD) or contact the transmission conductors.
Strengths Identified	**Noteworthy Items Identified**
> Targeted line clearing work. Adds clarity to the work expectations for the crews and stakeholders > Quality Assurance and Operations Support Team audit is a valuable check > Herbicide specialist on staff > Vegetation patrols contain sufficient level of detail for planning and budget projections > Operations cost estimates are well-developed > Robust notification process and education of stakeholders	> Development of forestry workforce and ability to retain personnel > Training program is sophisticated and well-maintained > "No hitter" policy for 500kV circuit > Use of mechanical treatment with follow up seeding of compatible species

Observations	Recommendations
Lack of centralized work management system	Develop cradle to grave project and work order management system. Database should ensure data continuity and track all pending and completed work activities. The system should integrate a GIS platform
Staff does not sign off work by span or smaller units	Implement a more granular approach to signing off completed work (i.e. by span rather than project)
Field resources are not familiar with the notification element of the imminent threat procedure	Reinforce and/or retrain the crews on the importance of communication with control center
Forestry Exception Log does not include relevant information needed to monitor issues.	Include a field that tracks more detailed location information (e.g. GPS location or span) and when further action would be needed to monitor or manage the issue
Herbicide efficacy is not reviewed or monitored in a formal manner	Enhance QA/QC procedure for the herbicide program
Missed opportunity with other department patrols as a tool to identify vegetation risks	Include a procedure to identify and respond to threatening vegetation
Aerial Vegetation patrols (AVPs) do not capture GPS coordinates	Include GPS units with AVP emergent work for further clarity of location

SCHEDULE B

Two excel documents have been filed separately under proceeding EB-2016-0160 which contain, respectively, the data provided to NATF (1) in the years 2008-2012; and (2) in the years 2013-2015.

SCHEDULE C

See attached tables summarizing the 2012-2015 Transmission Reliability Reports.

NATF Transmission Reliability Reports

The first NATF Reliability Report that included Hydro One's information was generated in 2013 and took into account Hydro One's outage data from 2008 to 2012. Given this, only NATF Reliability Reports between 2012 and 2015 include Hydro One information.

The NATF Reliability Report is organized into two groups. The first is Integrated Performance Indicator Index ("**IPII**"). The IPII is a numeric (0-100 points) representing member performance based on an aggregated set of weighted inputs.

Hydro One's IPII quartile ranking on its Total IPII Score and individual parametres are shown below.

	Quartile			
	2012	**2013**	**2014**	**2015**
Number of Participants (including Hydro One)	21	21	21	21
IPII Total Score	3	3	2	3
IPII Score Failed AC Circuit Equipment per Hundred Miles	3	3	3	4
IPII Score Failed AC Substation Equipment per Element	2	1	1	2
IPII Score Failed Protection System per Element	4	3	3	1
IPII Score Human Error per Element	3	2	1	1
IPII Score AC Circuit Unavailability per Element per Year	3	3	2	4
IPII Score AC Transformers Unavailability per Element per Year	2	2	3	3
IPII Score Unknowns per Hundred Miles	2	2	2	2
IPII Score Lightning per Hundred Miles	4	3	3	3
IPII Score Weather Excluding Lightning per Hundred Miles	2	2	2	2
IPII Score Aggregate Residual Causes per Hundred Miles	4	3	3	3

The second group concerns Traditional Reliability Metrics. Outage rates and durations normalized per circuit/element, and circuit/mile, for circuits (200-799kV) are reported. Hydro One's One-Year Quartile Ranking on Traditional Reliability Metrics is shown in the below table.

	Quartile			
	2012	**2013**	**2014**	**2015**
Number of Participants (including Hydro One)	21	21	21	21
AC Circuit Outage Rate per Hundred Miles per Year 200-799 kV	2	3	3	2
AC Circuit Outage Rate per Element per Year 200-799 kV	4	4	4	3
AC Circuit Average Outage Rate Duration of Sustained Outages 200-799 kV	3	3	2	4
AC Circuit Outage Rate Per Hundred Miles per Year-Momentary 200-799 kV	3	4	3	2
AC Circuit Outage Rate per Element per Year Rate-Momentary 200-799 kV	4	4	4	3
AC Circuit Outage Rate per Hundred Miles per Year-Sustained 200-799 kV	2	3	3	2
AC Circuit Outage Rate per Element per Year-Sustained 200-799 kV	2	4	3	3

Hydro One's Five-Year Quartile Ranking on Traditional Reliability Metrics is shown in the below table.

	Quartile			
	2012	**2013**	**2014**	**2015**
Number of Participants (including Hydro One)	21	21	21	21
AC Circuit Outage Rate per Hundred Miles per Year 200-799 kV	3	4	3	3
AC Circuit Outage Rate per Element per Year 200-799 kV	4	4	4	4
AC Circuit Average Outage Rate Duration of Sustained Outages 200-799 kV	2	3	2	2
AC Circuit Outage Rate Per Hundred Miles per Year-Momentary 200-799 kV	4	4	4	3
AC Circuit Outage Rate per Element per Year Rate-Momentary 200-799 kV	4	4	4	4
AC Circuit Outage Rate per Hundred Miles per Year-Sustained 200-799 kV	2	2	3	3
AC Circuit Outage Rate per Element per Year-Sustained 200-799 kV	3	3	4	4

SCHEDULE D

See attached example of the Wanstead Transformer Station Refurbishment Business Case Summary.

Wanstead Transformer Station Refurbishment

Overview of Recommended Alternative:

We are requesting approval for $33.7 million to replace deteriorated and end of life equipment at Wanstead Transformer Station by rebuilding the station in a greenfield location on the existing property to minimize outages to customers. Including development expenditures to date, the total project cost is $33.8 million. In accordance with customer requests, the station will be reconnected from the 115kV transmission system to the 230kV system to improve reliability performance.

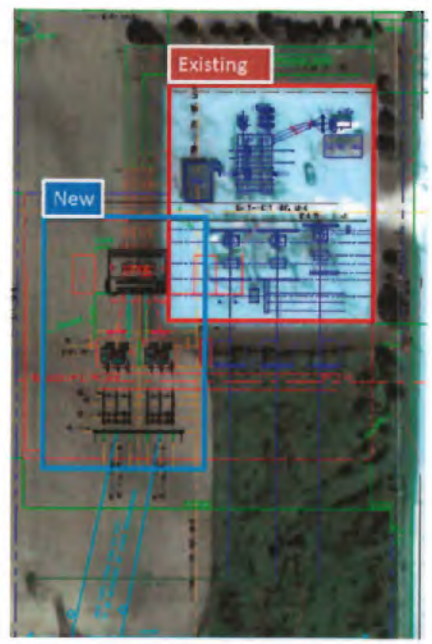
Investment Details:

In-service: Nov 30, 2018

Wanstead Transformer Station was originally built in 1949 in the County of Plympton in southwestern Ontario and supplies approximately 54MW to Hydro One Distribution and the embedded Local Distribution Company - Bluewater Power via three 18/27/33 MVA, 115-27.6 kV power transformers and four 27.6kV feeders. The local distribution companies supply power to the municipalities of Alvinston, Oil Springs, Petrolia, and Watford.

Leaking Transformers with no Spill Containment

The three existing non-standard Canadian Westinghouse power transformers, low voltage switchgear and associated protection, control and teleprotection facilities are at end of life due to their poor condition, obsolescence and declining performance as verified through visual inspection and diagnostic testing. The station is also #1 out of Hydro One's 291 transformer stations in terms of environmental spill risk ranking.



Footprint of the present and the new Wanstead TS

This investment will result in the complete rebuild and reconfiguration of Wanstead Transformer Station in a greenfield location. The scope of the work will include replacement of the three non-standard transformers and associated deteriorated infrastructure with two new standard 50/83 MVA transformers, construction of the medium voltage gas insulated indoor switchgear, and protection, control and teleprotection facilities that adhere to the current standards. To address environmental issues and to meet current Ministry of Environment and Climate Change requirements, spill containment, drainage and oil/water separator facilities will be also installed on the new transformers.

At the request of Hydro One Distribution and Bluewater Power, the station will be reconnected from the 115kV transmission system via the existing radial circuit S2N to the 230kV system supplied from the two circuits N21W and N22W. The system enhancements will improve the reliability of the supply. In accordance with the Transmission System Code, a Connection and Cost Recovery Agreement will be in place with the customers. Approval to proceed with the investment is contingent on agreed and signed contract that is to be executed by Key Accounts on behalf of Hydro One Inc.

Benefits:

The investment will provide the following benefits:

(a) Reduce the risk of customer delivery point interruptions and improve the reliability of supply by approximately 10 times its current level.

(b) Meet customer commitments and request for improved reliability of supply.

(c) Meet current Hydro One design standards and Ministry of Environment and Climate Change requirements

(d) Reduce the ongoing annual maintenance costs from $170K to $40K.

Estimated Costs & In-service:

This is a multi-year project, with all capital costs to be in-serviced in 2018.

The cost breakdown is as follows:

Category	Cost ($M)
Project Services	0.9
Engineering	1.8
Procurement	13.2
Construction	7.3
Station service work management	1.8
Contingency	1.2
Interest & Overhead	6.8
Previous Expenditures	0.5
Total	**33.8**

The previous approval of $0.1M was for engineering and estimating. The necessary engineering has been completed to achieve an estimate accuracy of +/-10%. The contingency is mainly related to Construction portion of the estimate to cover the risk that the outsourced bids will be higher than originally estimated.

This investment is included in the approved 2016 Budget and will be included in the 2017 business plan.

Other Alternatives Considered

Status Quo or Do nothing Alternative

The equipment at Wanstead Transformer Station is non-standard, in deteriorated condition, at end of life, poses significant environmental risks, has ongoing reliability issues and excessive maintenance costs. By continuing with the status quo, Hydro One will be exposed to increased risk of equipment failures and customer interruptions and as such, the status quo option is rejected.

Regulatory Considerations

$0.1 million for estimate preparation for this project is included in Hydro One's approved 2015/16 Transmission Rate Filing [EB-2014-140]. The total planned project expenditures and related in-service values will be included in the 2017/2018 rate application that Hydro One intends to file with the Ontario Energy Board in May 2016. Hydro One considers the risk of non-recovery of these expenditures to be low because this investment will address equipment risks that exist at the station and will provide customer supportable benefits.

Risks and Mitigation

First Nations and Metis Relations

The work to be completed will take place in a greenfield location on the existing property and a Class Environmental Assessment is required. In the context of conducting the Class Environmental Assessment Hydro One will notify the surrounding First Nations and Metis communities that may have Aboriginal and treaty rights, lands or interests which may be potentially affected by the project. Current risk is assessed to be medium as Hydro One will notify in writing the surrounding First Nations and Metis Communities about the project prior to commencement of the Class Environmental Assessment process and offer to meet. This approach has proven to be successful with respect to other similar projects.

Environmental Assessment

The severity of the soil contamination of the existing site (including the greenfield location) and the effort towards soil remediation will only be identified after the soil investigation has been completed. The existing station has had mineral oil leakage and the current estimate includes sufficient funding for on-site soil remediation. The results of the environmental site assessment will also determine the risk of any off-site contamination that has occurred. This is considered medium-risk as no additional funding has been allocated to deal with off-site soil remediation.

Resourcing

The current cost estimate is based on the assumption that the project will be executed using internal construction resources. To meet the in-service date, it is expected that construction will have to be outsourced with a potential for the construction costs from external bids coming in higher than anticipated. This risk to total project cost is expected to be moderate and the contingency is mainly to address this risk.

This Approval ($M): 33.7	Previous Approval ($M): 0.1	Total Approval ($M): 33.8
Signature Block:		
Approved by: Mike Penstone	Title: Vice President, Planning	Date:
Approved by: Karen Newman	Title: Vice President, Corporate Controller	Date: May 18/16
Approved by: Michael Vels	Title: Chief Financial Officer	Date:
Approved by: Mayo Schmidt	Title: President & CEO	Date: May 20, 2016

Required SAP Data

Yearly Expenditures

	2016($M)	2017($M)	2018($M)	2019 ($M)	Total ($M)
Capital* and MFA	0.6	13.5	16.3	2.6	33.2
OM&A and Removals	0.5	0.1	-	-	0.6
Gross Investment Cost*	1.1	13.6	16.3	2.6	33.8
Recoverable	0.3	0.3	0.3	0.2	1.1
Net Investment Cost	0.8	13.3	16.0	2.4	32.7

*Includes capitalized interest and overhead at current rates

	2016($M)	2017($M)	2018 ($M)	Total($M)
In-Service $ Additions	0	0	32.1	32.1

In-service Date:	Nov 30, 2018
Business Case Summary #:	51000264
Appropriation Request #:	22949, 23694
Subject ID #	80751
Investment Driver:	T.C.1.40, D.C.2.02
Productivity Cards?	No
Director	Chong Kiat Ng
Planner	Gaurav Kumar

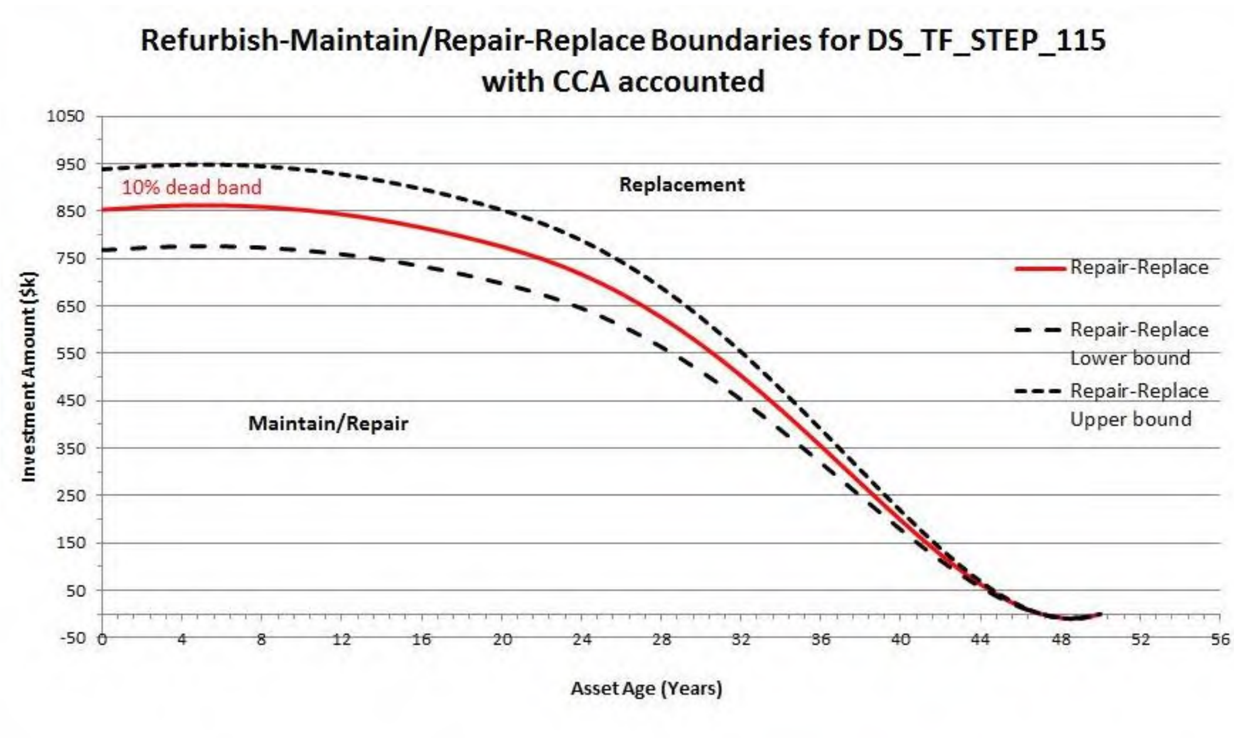
Scientific Research & Experimental Development Tax Credits (SR&ED):

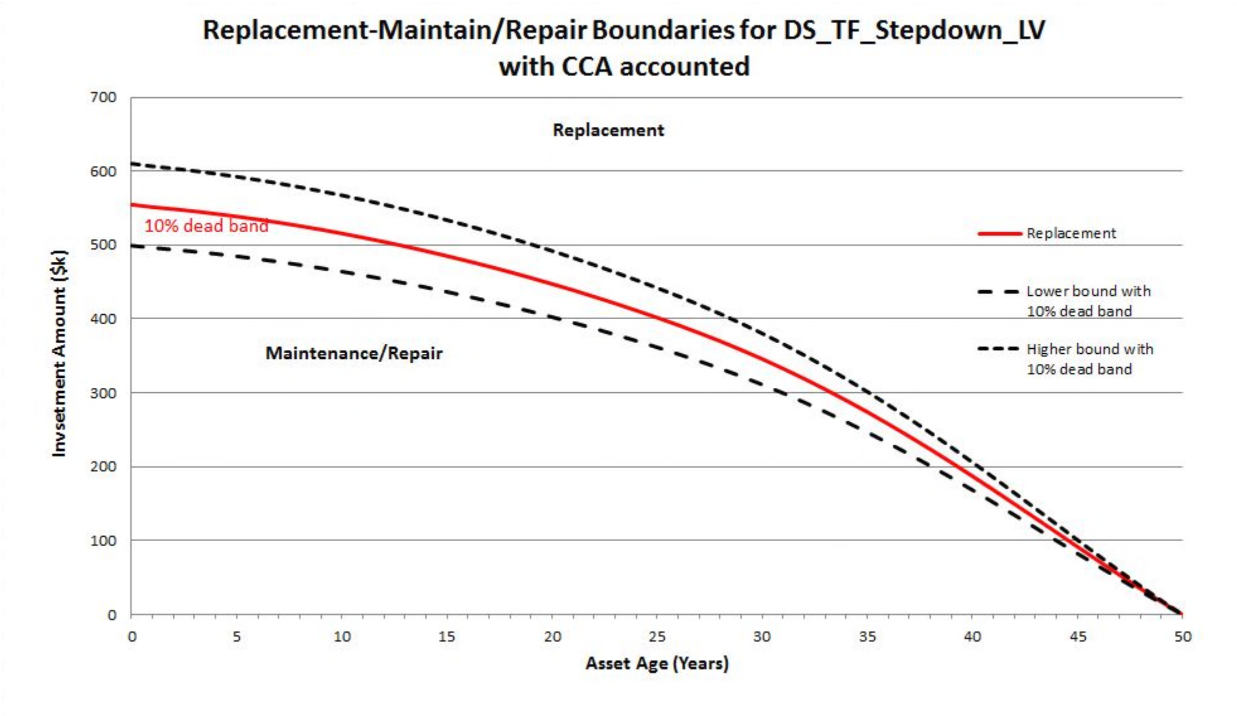
- Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? No

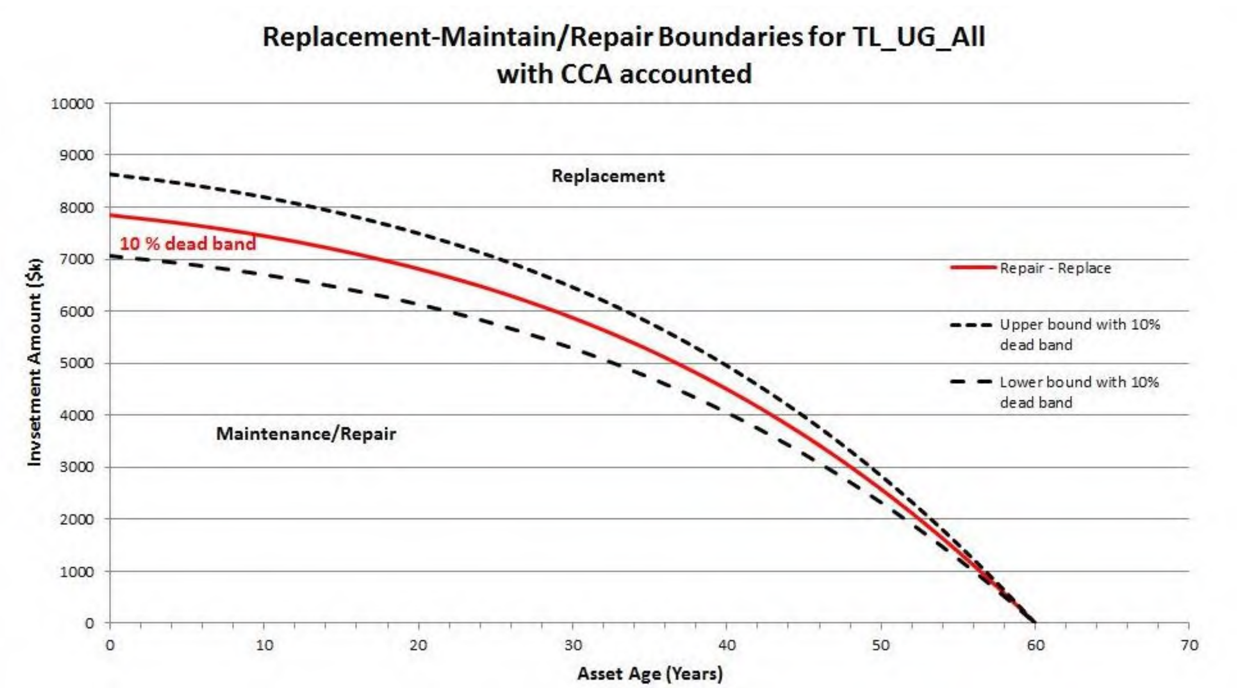
SCHEDULE E

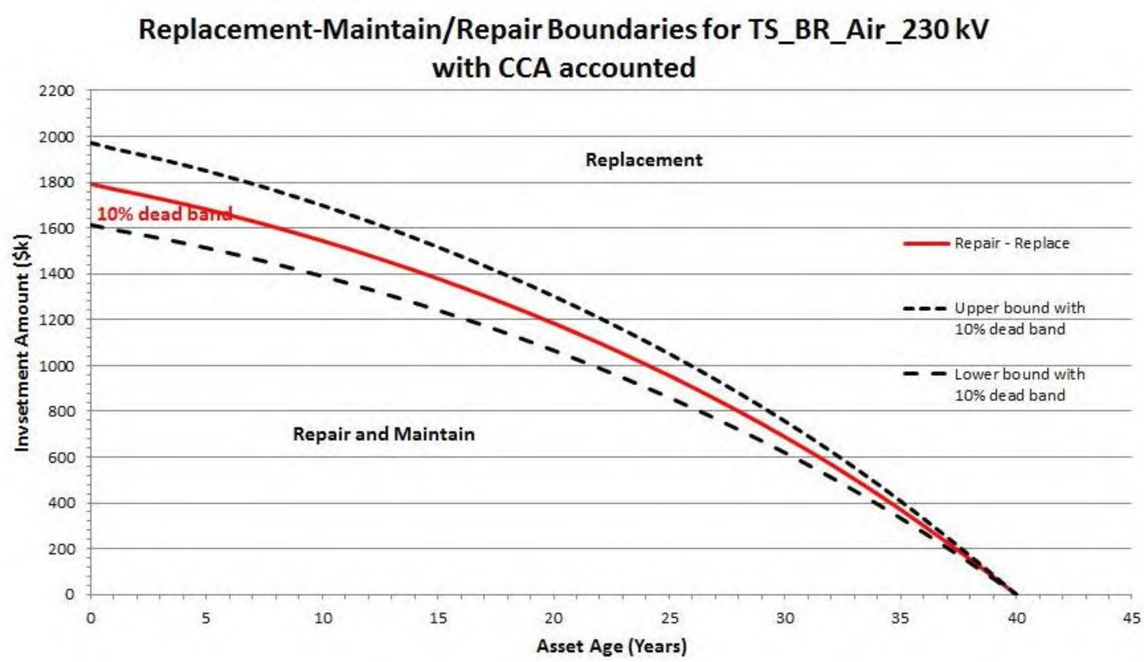
See attached:

- Examples of standard economic analysis charts for oil, SF6, and ABCB breakers; and
- Examples of business case summaries relating to the following circuit breakers:
  - Beck #2 Air Blast Circuit Breaker (described in TCJ1.33);
  - Barrett Chute (described in Exhibit B1-3-11, Investment Summary Document S21); and
  - Martindale TS (described in Exhibit B1-3-11, Investment Summary Document S40).

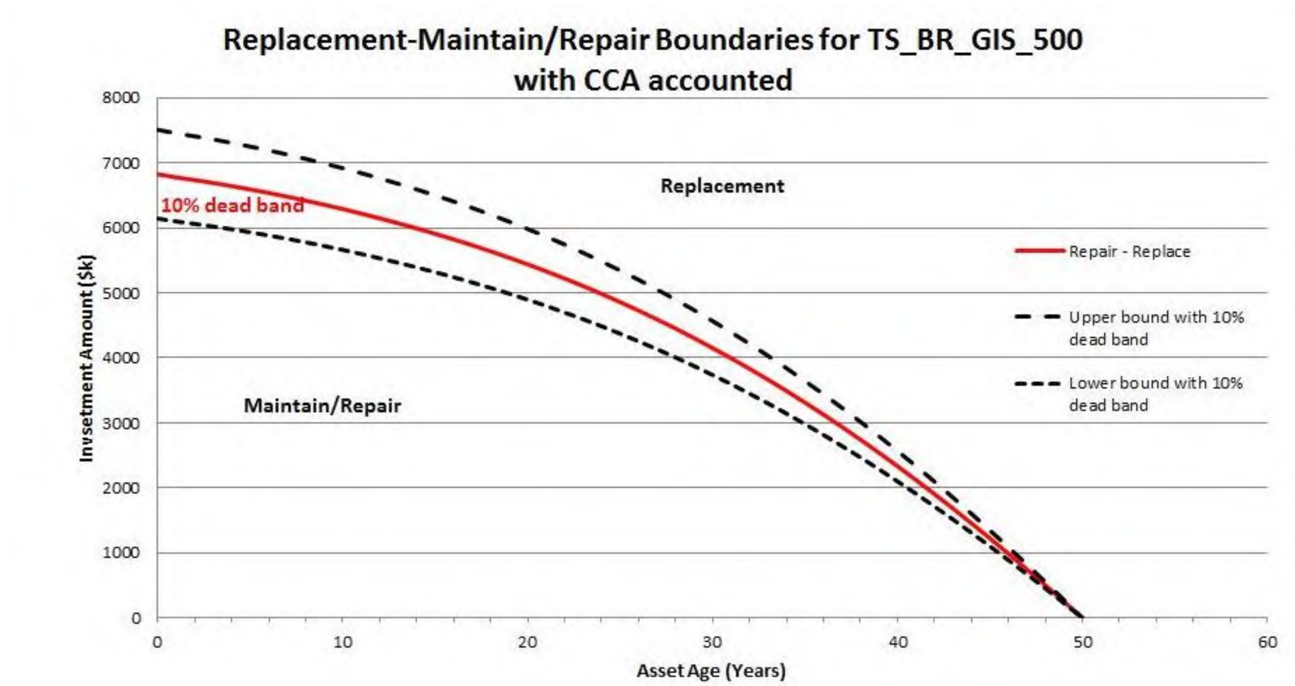

Refurbish-Maintain/Repair-Replace Boundaries for DS_TF_STEP_115
with CCA accounted
10% dead band
Replacement
Maintain/Repair
Repair-Replace
Repair-Replace Lower bound
Repair-Replace Upper bound
Investment Amount ($k)
Asset Age (Years)
1050
950
850
750
650
550
450
350
250
150
50
-50
0
4
8
12
16
20
24
28
32
36
40
44
48
52
56


Replacement-Maintain/Repair Boundaries for DS_TF_Stepdown_LV
with CCA accounted
Replacement
10% dead band
Maintenance/Repair
Replacement
Lower bound with
10% dead band
Higher bound with
10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
100
200
300
400
500
600
700
0
5
10
15
20
25
30
35
40
45
50

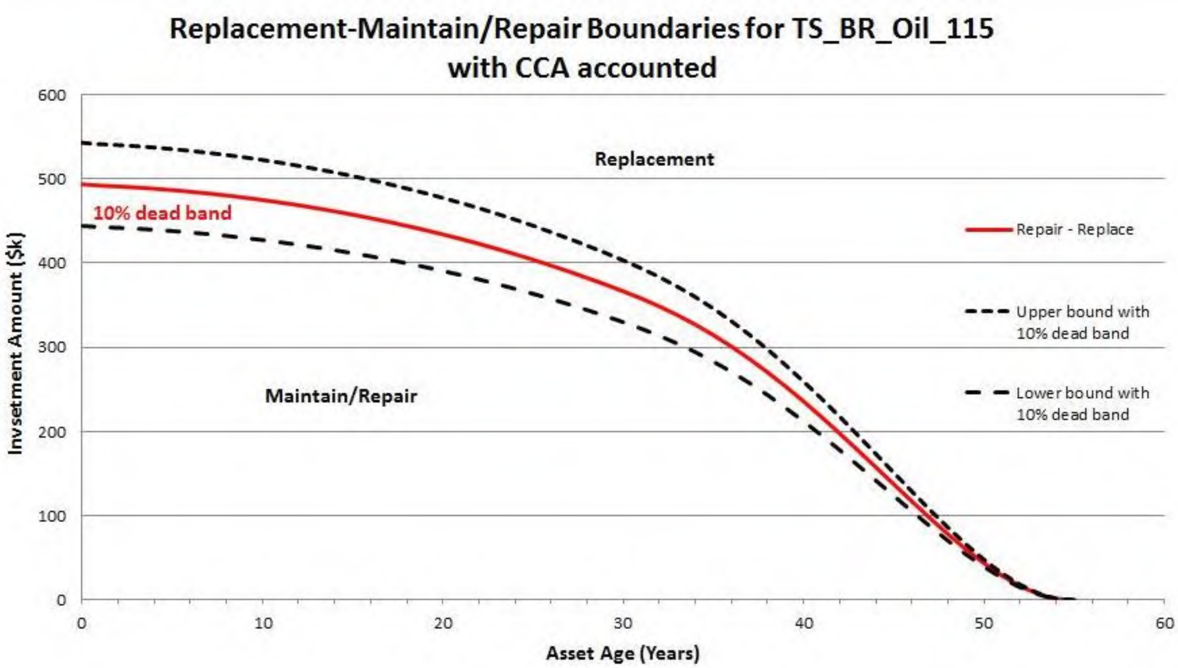

Replacement-Maintain/Repair Boundaries for TL_UG_All
with CCA accounted
Replacement
10 % dead band
Maintenance/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
0
10
20
30
40
50
60
70

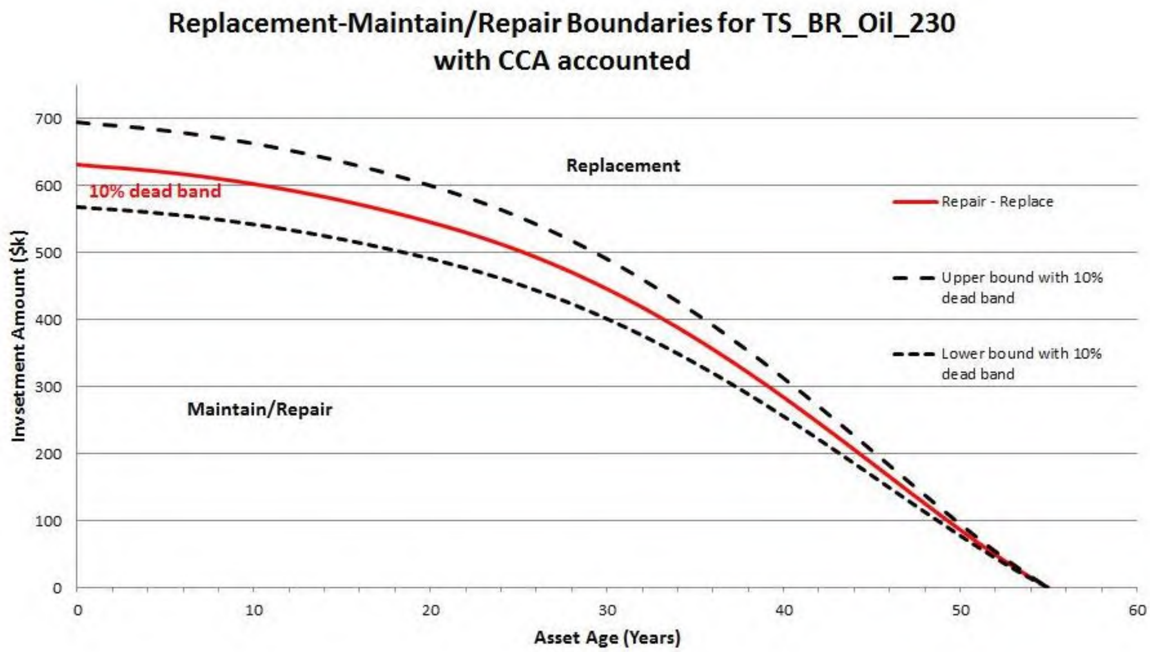


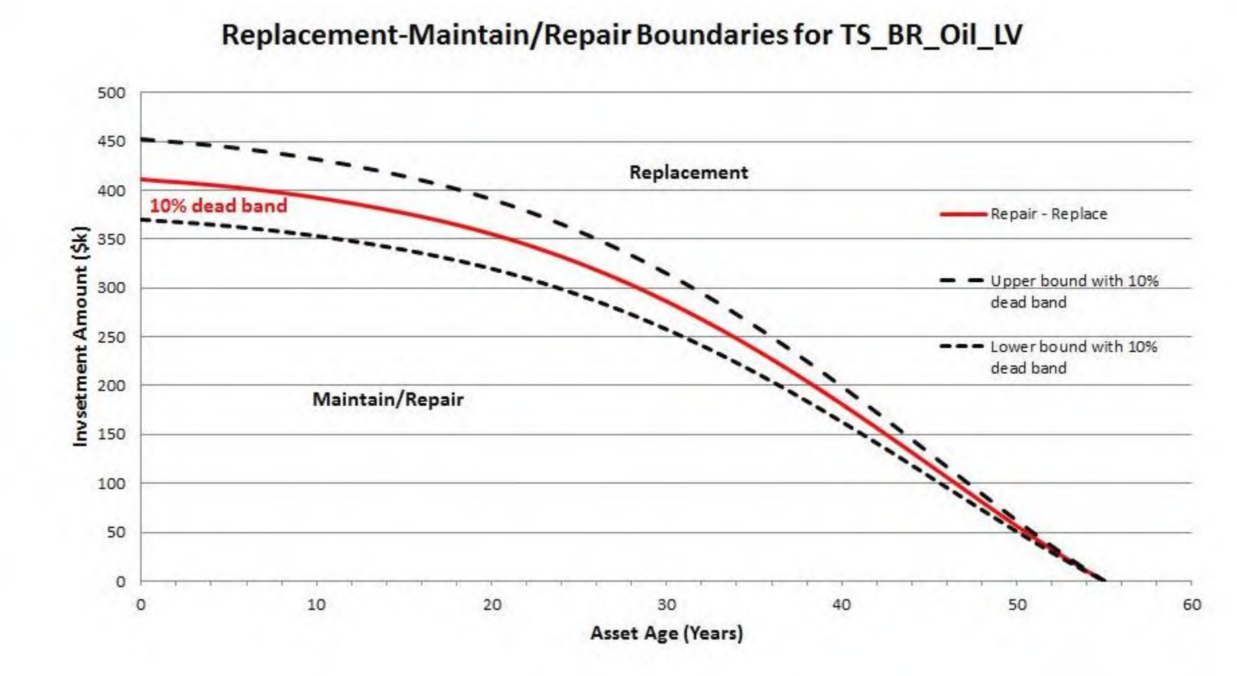
Replacement-Maintain/Repair Boundaries for TS_BR_Air_230 kV
with CCA accounted
Replacement
10% dead band
Repair and Maintain
Repair - Replace
Upper bound with
10% dead band
Lower bound with
10% dead band
Invsetment Amount ($k)
Asset Age (Years)
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
0
5
10
15
20
25
30
35
40
45

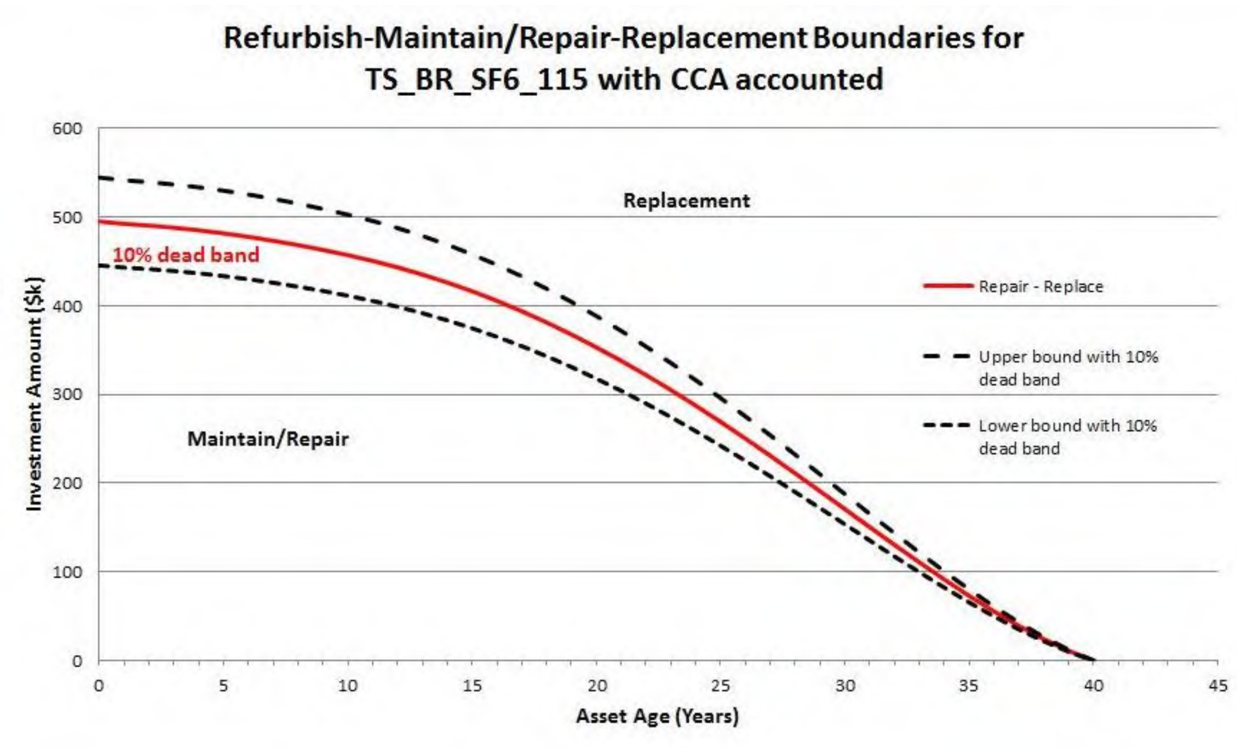


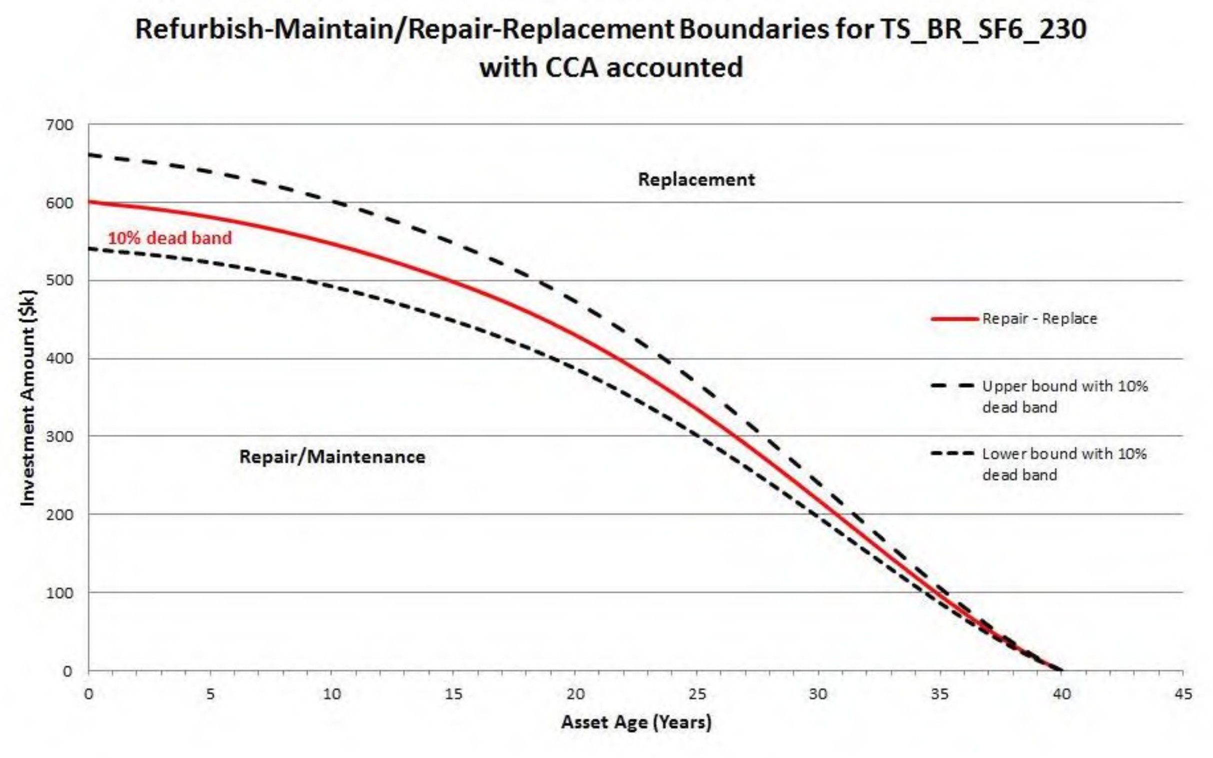
Replacement-Maintain/Repair Boundaries for TS_BR_GIS_500
with CCA accounted
8000
7000
6000
5000
4000
3000
2000
1000
0
Invsetment Amount ($k)
0
10
20
30
40
50
60
Asset Age (Years)
Replacement
10% dead band
Maintain/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band

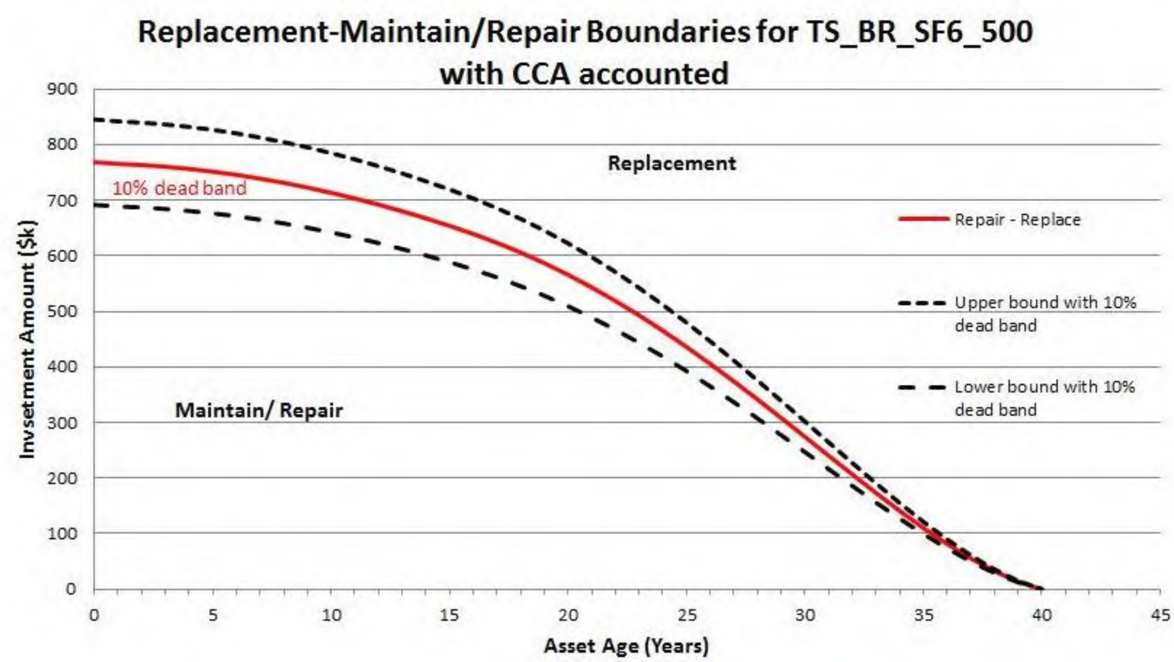

Replacement-Maintain/Repair Boundaries for TS_BR_Oil_115
with CCA accounted
Replacement
10% dead band
Maintain/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
100
200
300
400
500
600
0
10
20
30
40
50
60

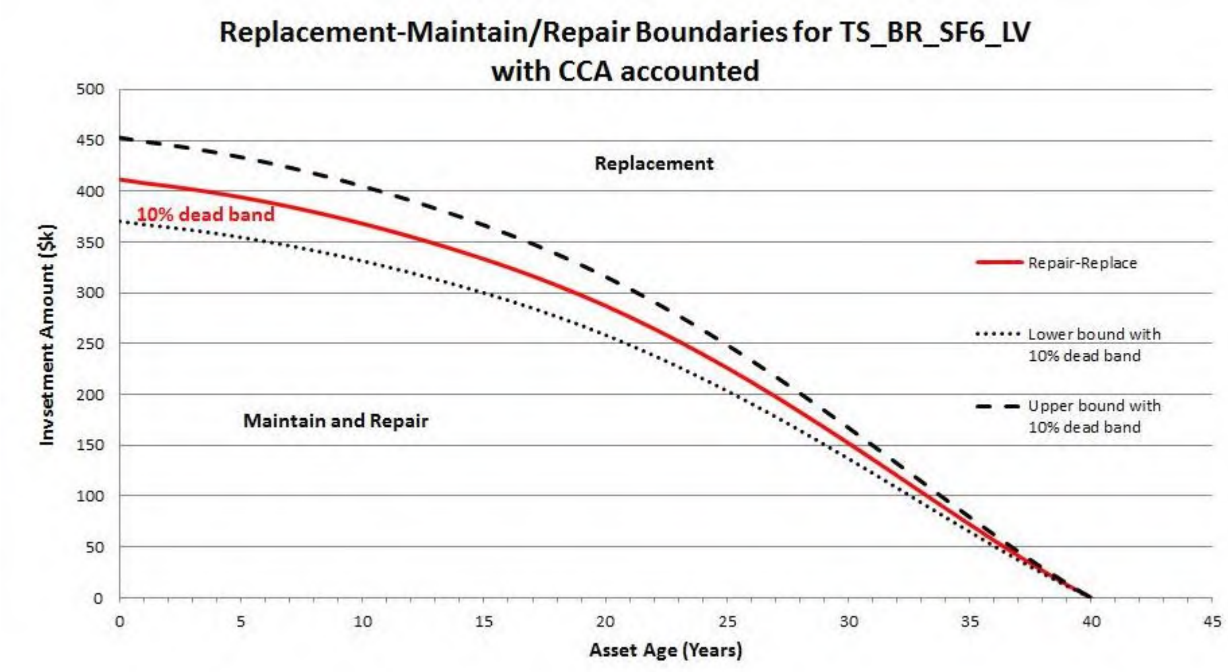

Replacement-Maintain/Repair Boundaries for TS_BR_Oil_230
with CCA accounted
Replacement
10% dead band
Maintain/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
700
600
500
400
300
200
100
0
0
10
20
30
40
50
60

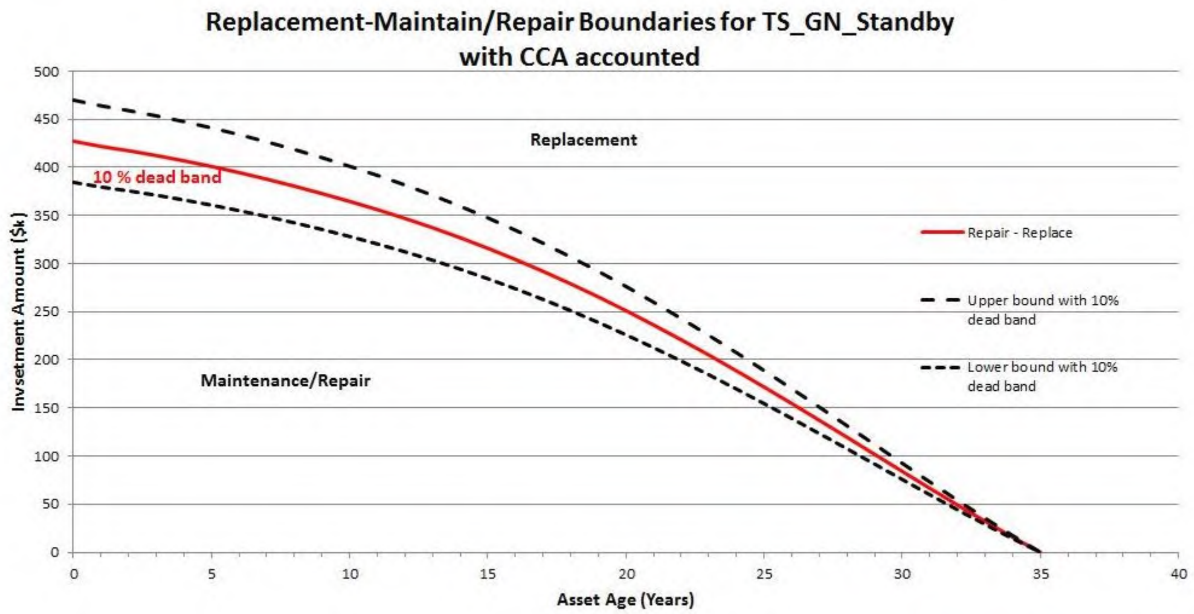

Replacement-Maintain/Repair Boundaries for TS_BR_Oil_LV
Replacement
10% dead band
Maintain/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
50
100
150
200
250
300
350
400
450
500
10
20
30
40
50
60

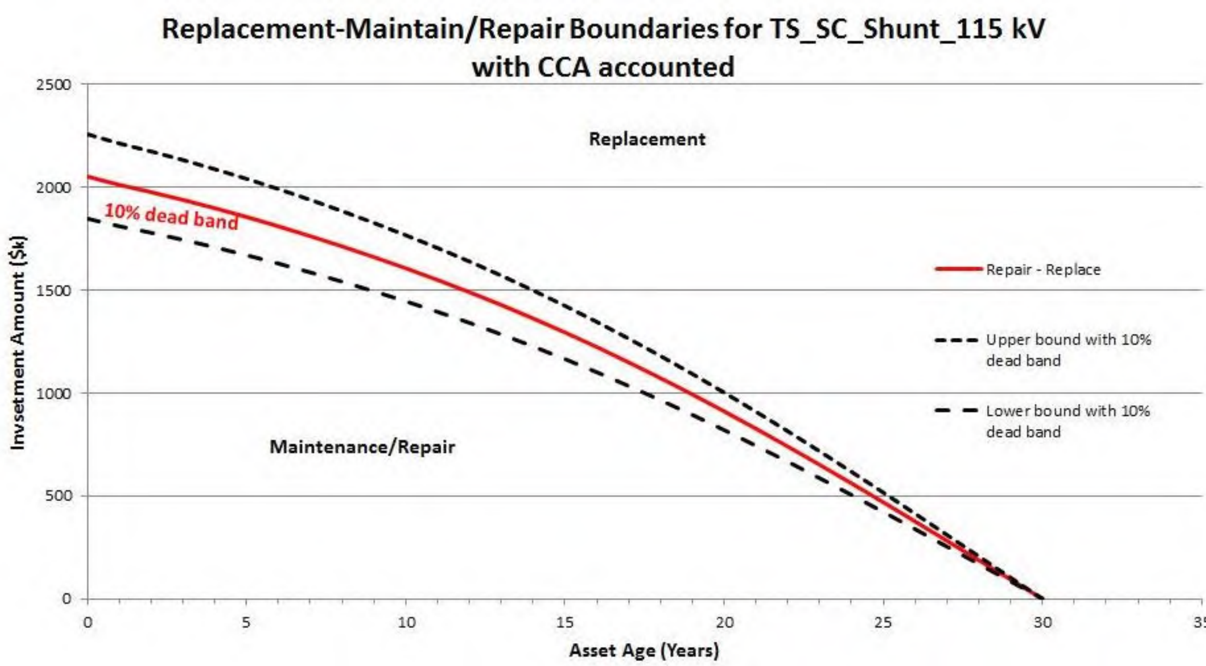

Refurbish-Maintain/Repair-Replacement Boundaries for TS_BR_SF6_115 with CCA accounted
Replacement
10% dead band
Maintain/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Investment Amount ($k)
Asset Age (Years)
600
500
400
300
200
100
0
0
5
10
15
20
25
30
35
40
45

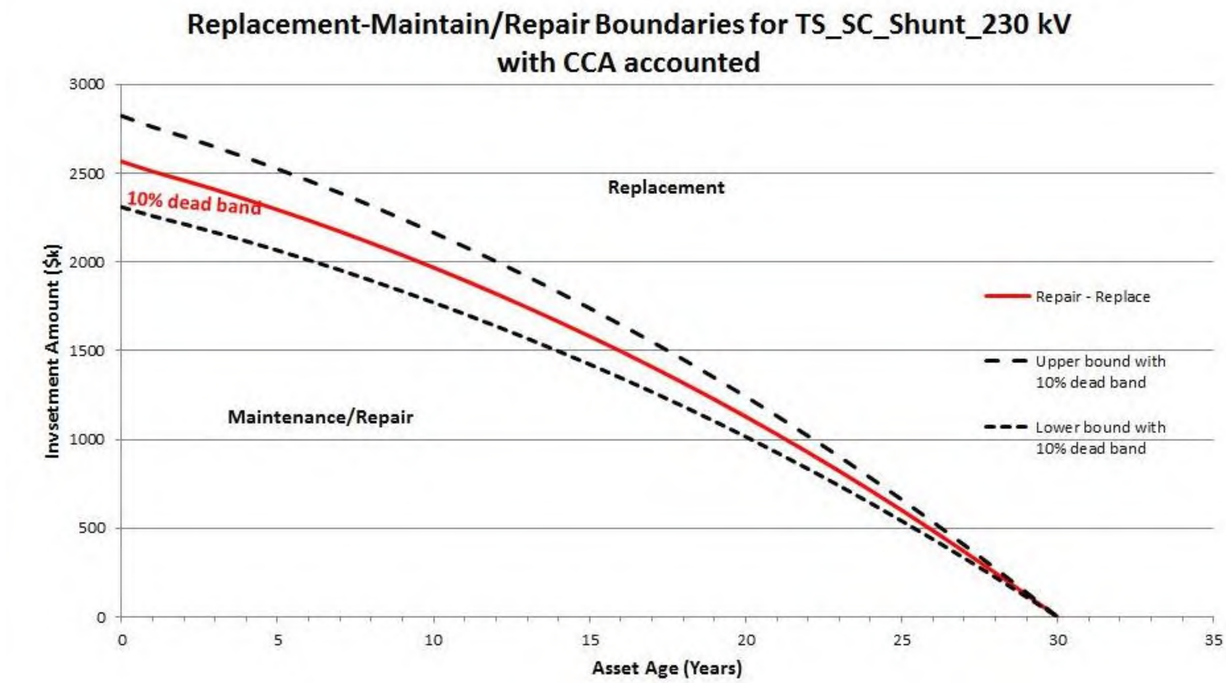

Refurbish-Maintain/Repair-Replacement Boundaries for TS_BR_SF6_230
with CCA accounted
Replacement
10% dead band
Repair/Maintenance
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Investment Amount ($k)
Asset Age (Years)
0
100
200
300
400
500
600
700
0
5
10
15
20
25
30
35
40
45

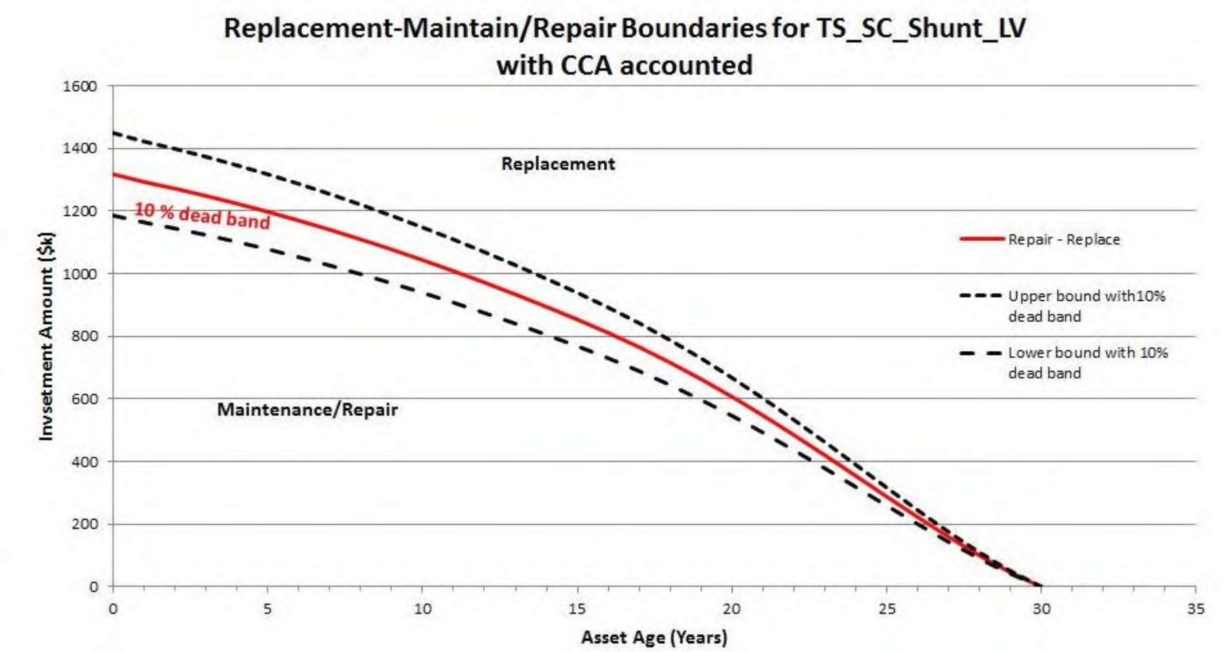

Replacement-Maintain/Repair Boundaries for TS_BR_SF6_500 with CCA accounted
900
800
700
600
500
400
300
200
100
0
0
5
10
15
20
25
30
35
40
45
Invsetment Amount ($k)
Asset Age (Years)
Replacement
10% dead band
Maintain/ Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band

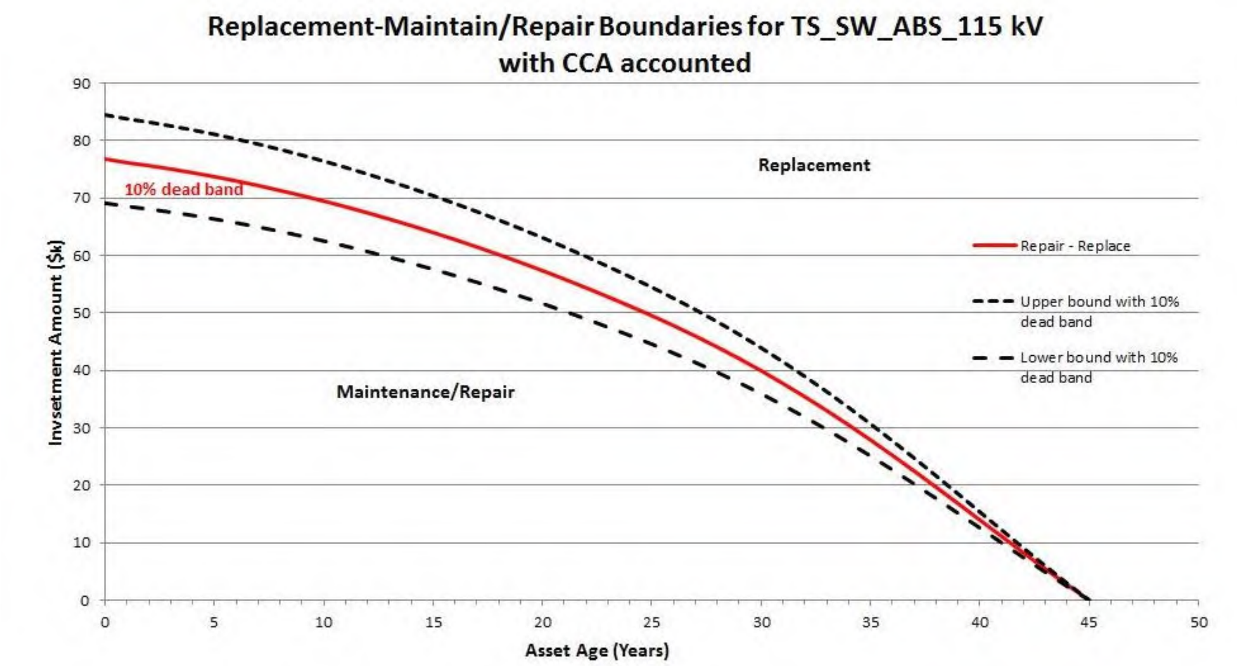

Replacement-Maintain/Repair Boundaries for TS_BR_SF6_LV
with CCA accounted
Replacement
10% dead band
Maintain and Repair
Repair-Replace
Lower bound with 10% dead band
Upper bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
50
100
150
200
250
300
350
400
450
500
0
5
10
15
20
25
30
35
40
45


Replacement-Maintain/Repair Boundaries for TS_GN_Standby
with CCA accounted
Replacement
10 % dead band
Maintenance/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
50
100
150
200
250
300
350
400
450
500
5
10
15
20
25
30
35
40

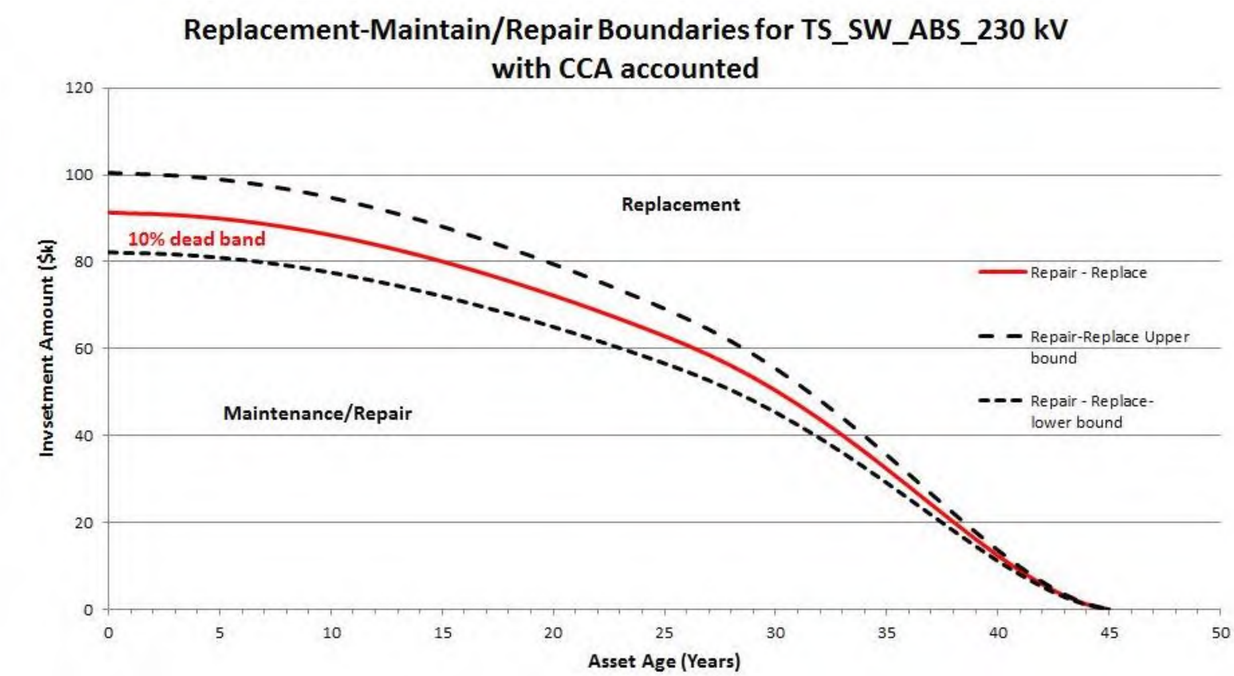

Replacement-Maintain/Repair Boundaries for TS_SC_Shunt_115 kV
with CCA accounted
Replacement
10% dead band
Maintenance/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
2500
2000
1500
1000
500
0
0
5
10
15
20
25
30
35

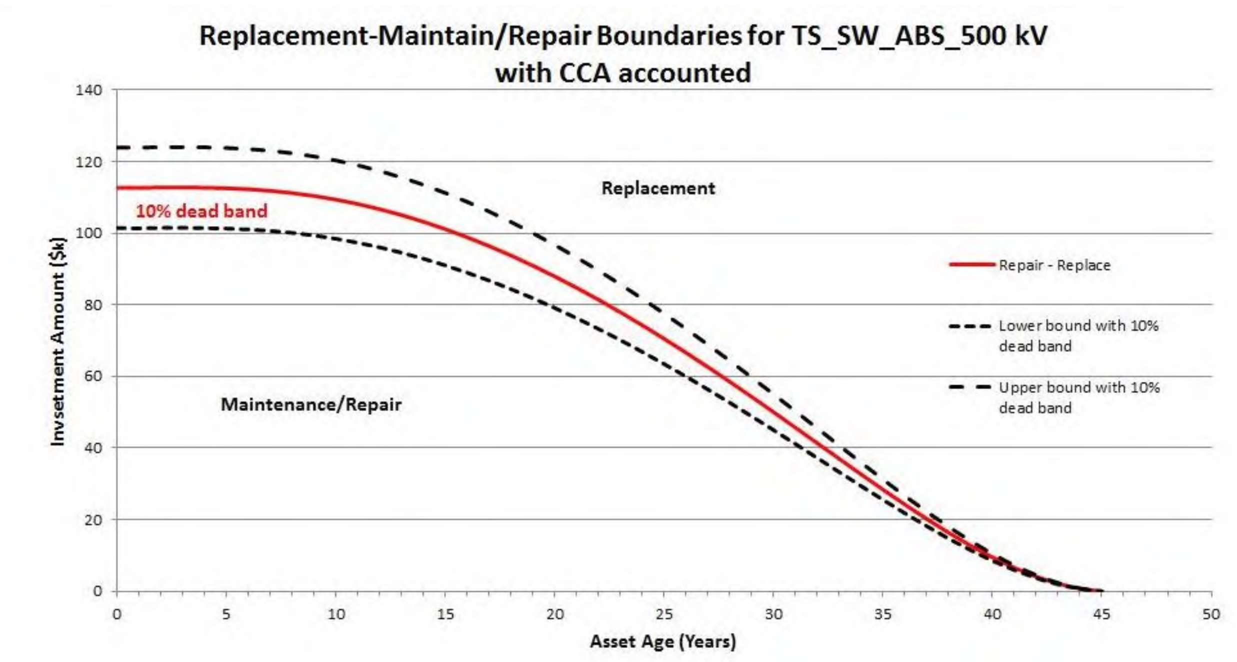

Replacement-Maintain/Repair Boundaries for TS_SC_Shunt_230 kV
with CCA accounted
Replacement
10% dead band
Maintenance/Repair
Repair - Replace
Upper bound with
10% dead band
Lower bound with
10% dead band
Invsetment Amount ($k)
Asset Age (Years)
3000
2500
2000
1500
1000
500
0
0
5
10
15
20
25
30
35

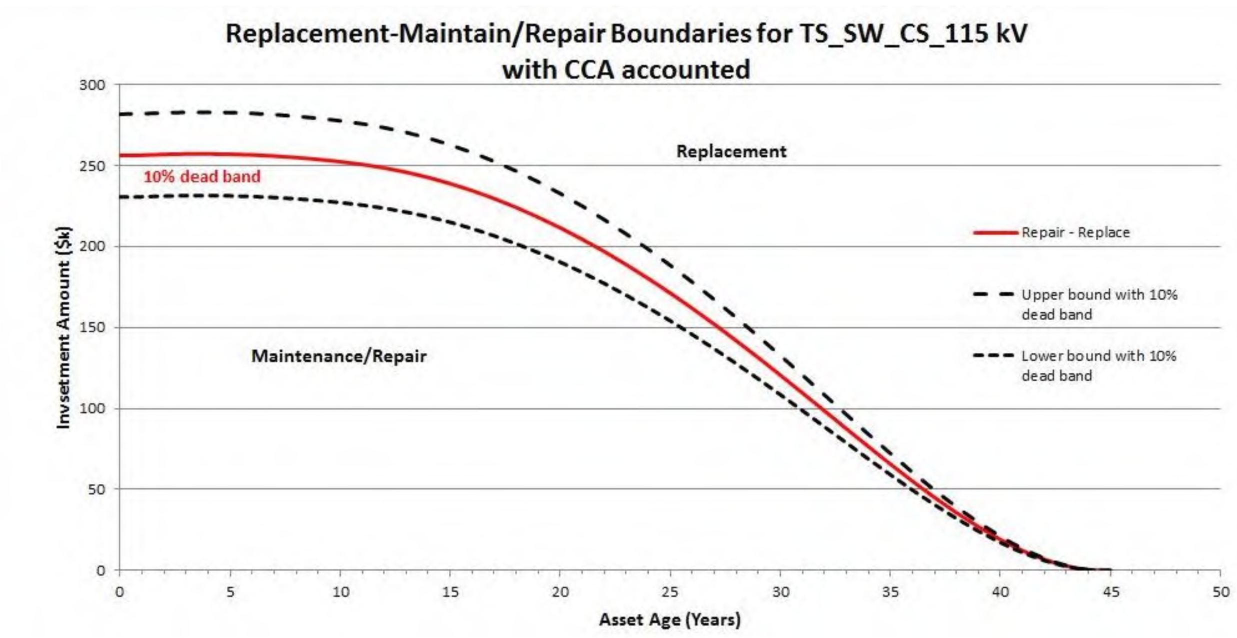

Replacement-Maintain/Repair Boundaries for TS_SC_Shunt_LV
with CCA accounted
Replacement
10 % dead band
Maintenance/Repair
Repair - Replace
Upper bound with10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
200
400
600
800
1000
1200
1400
1600
0
5
10
15
20
25
30
35

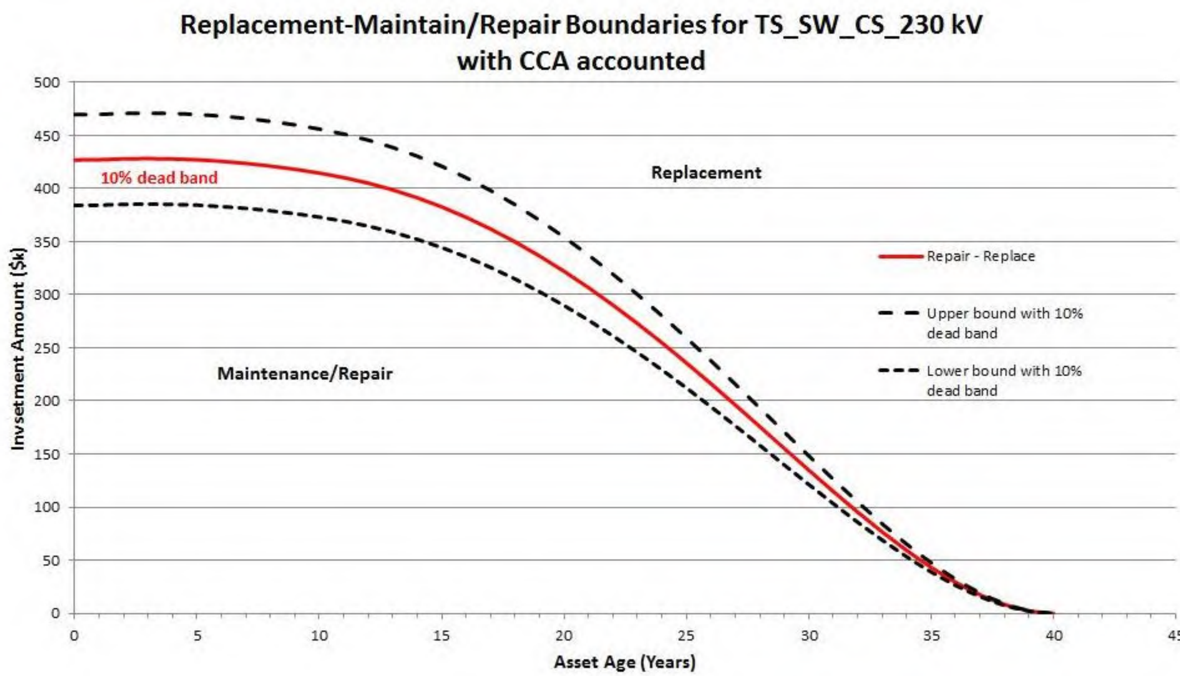


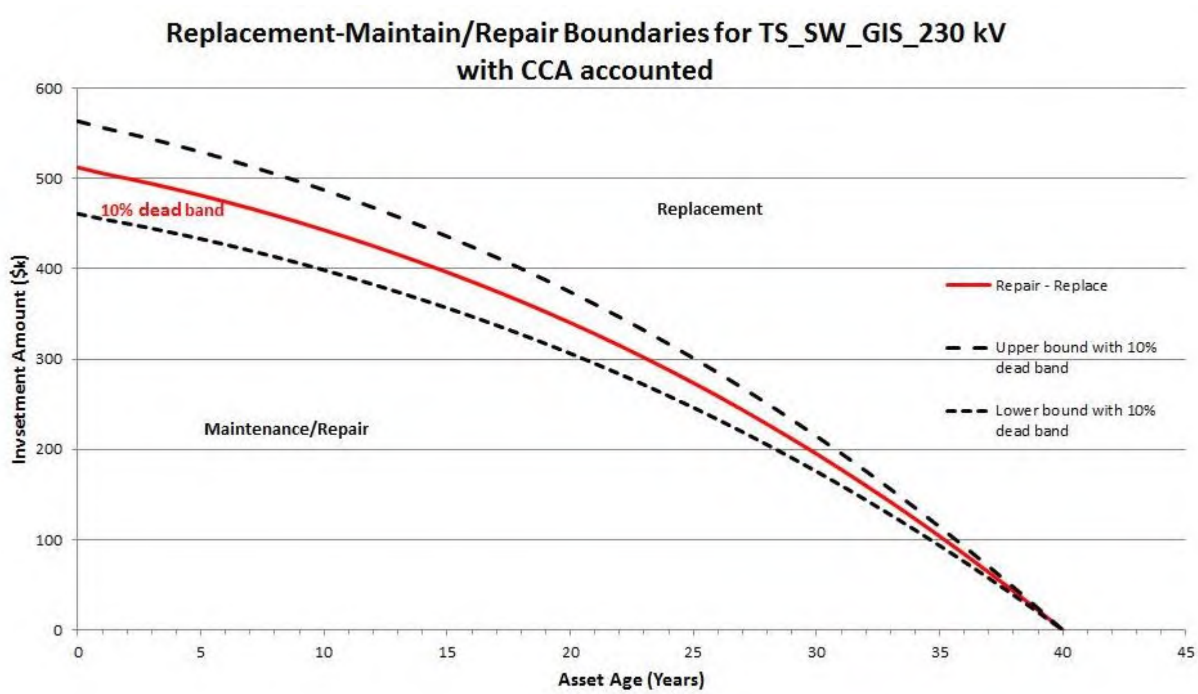
Replacement-Maintain/Repair Boundaries for TS_SW_ABS_115 kV
with CCA accounted
Replacement
10% dead band
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Maintenance/Repair
Invsetment Amount ($k)
Asset Age (Years)
0
10
20
30
40
50
60
70
80
90
0
5
10
15
20
25
30
35
40
45
50


Replacement-Maintain/Repair Boundaries for TS_SW_ABS_230 kV with CCA accounted
120
100
80
60
40
20
0
Invsetment Amount ($k)
Replacement
10% dead band
Maintenance/Repair
Repair - Replace
Repair-Replace Upper bound
Repair - Replace- lower bound
0
5
10
15
20
25
30
35
40
45
50
Asset Age (Years)

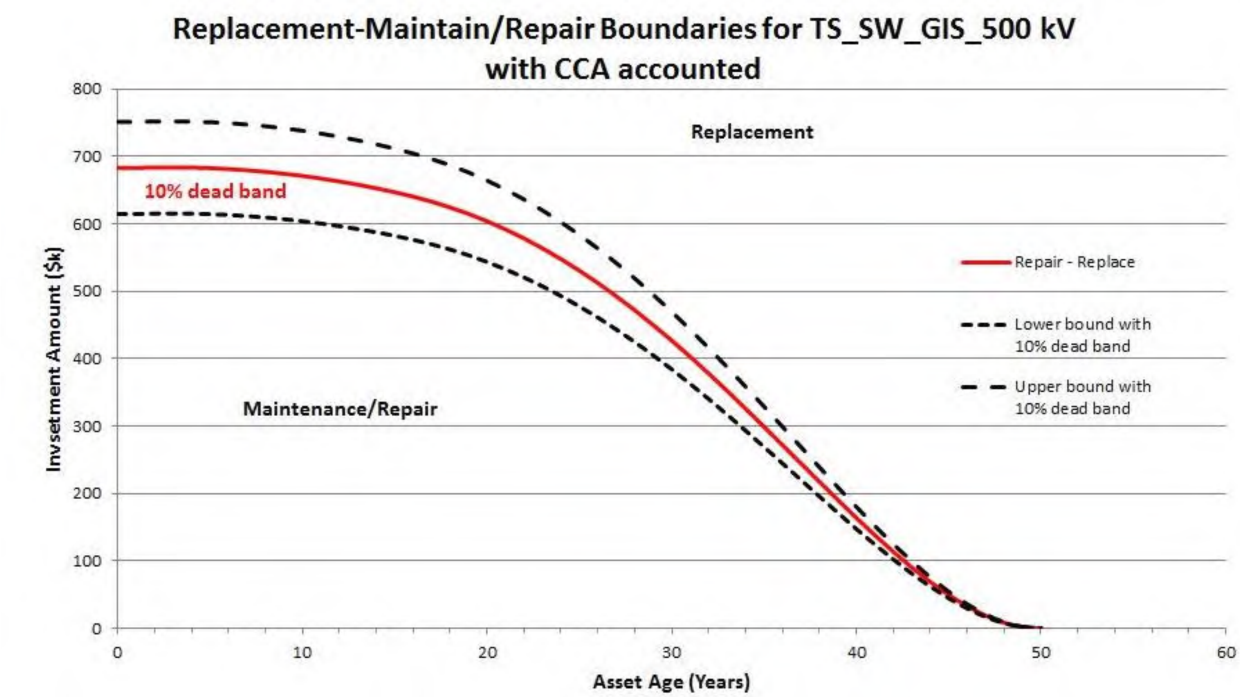

Replacement-Maintain/Repair Boundaries for TS_SW_ABS_500 kV
with CCA accounted
Replacement
10% dead band
Maintenance/Repair
Repair - Replace
Lower bound with 10% dead band
Upper bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
20
40
60
80
100
120
140
0
5
10
15
20
25
30
35
40
45
50

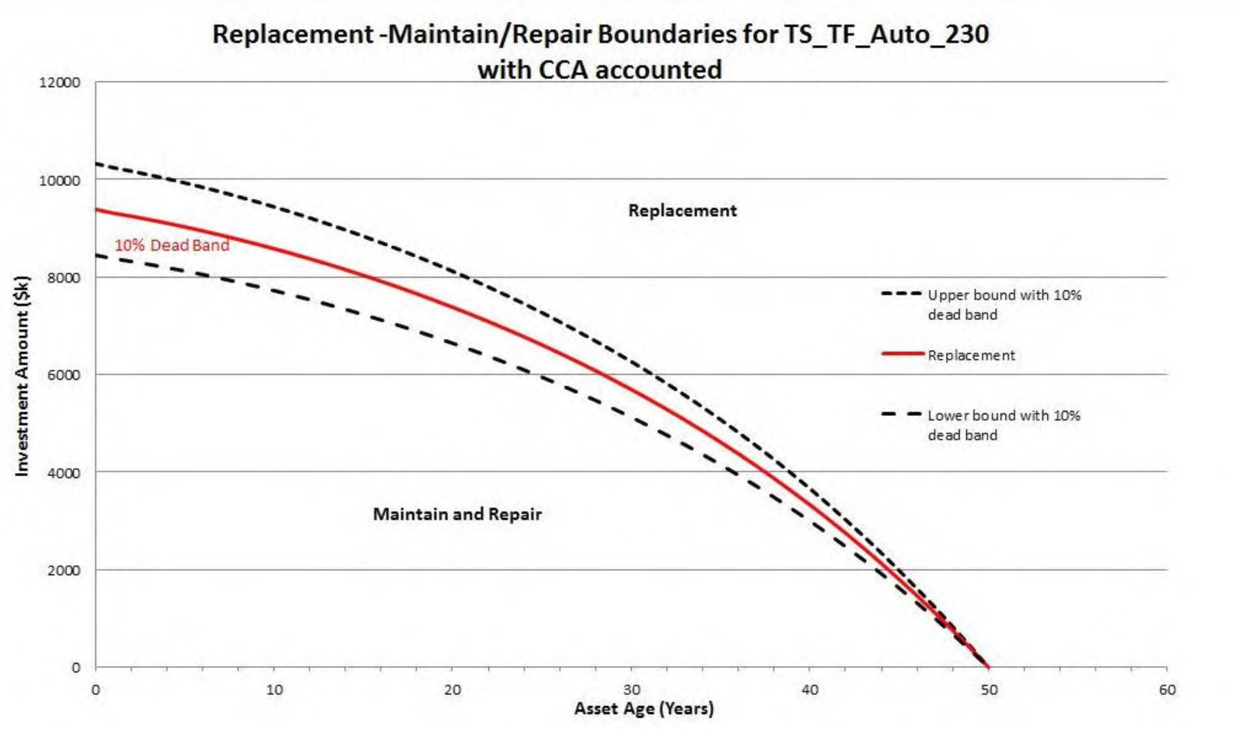

Replacement-Maintain/Repair Boundaries for TS_SW_CS_115 kV with CCA accounted
Replacement
10% dead band
Maintenance/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
300
250
200
150
100
50
0
0
5
10
15
20
25
30
35
40
45
50

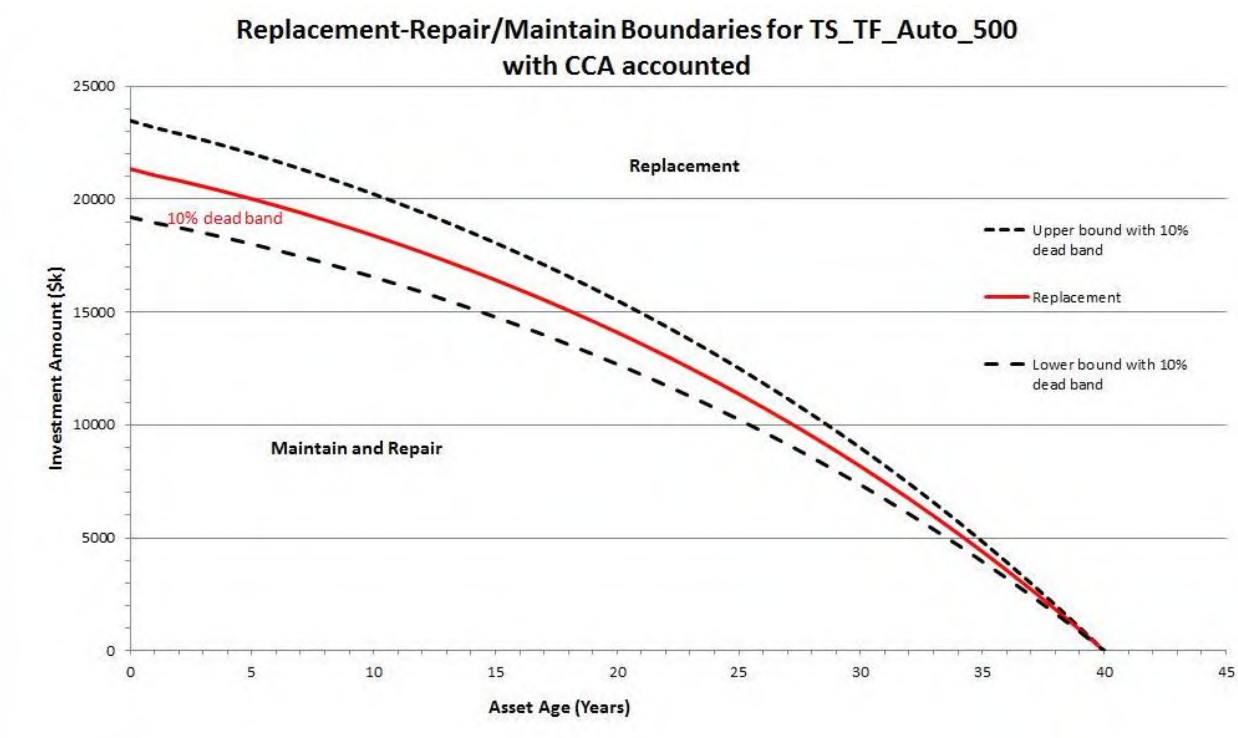

Replacement-Maintain/Repair Boundaries for TS_SW_CS_230 kV
with CCA accounted
10% dead band
Replacement
Maintenance/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
500
450
400
350
300
250
200
150
100
50
0
0
5
10
15
20
25
30
35
40
45

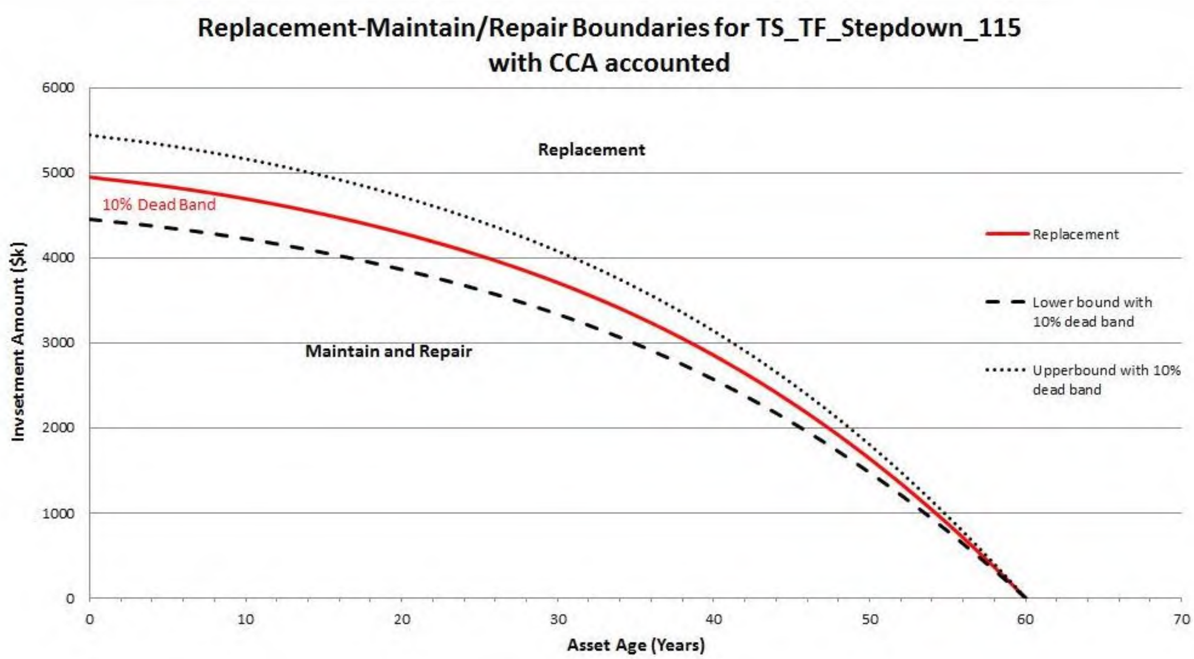


Replacement-Maintain/Repair Boundaries for TS_SW_GIS_230 kV
with CCA accounted
Invsetment Amount ($k)
600
500
400
300
200
100
0
10% dead band
Replacement
Maintenance/Repair
Repair - Replace
Upper bound with 10% dead band
Lower bound with 10% dead band
0
5
10
15
20
25
30
35
40
45
Asset Age (Years)

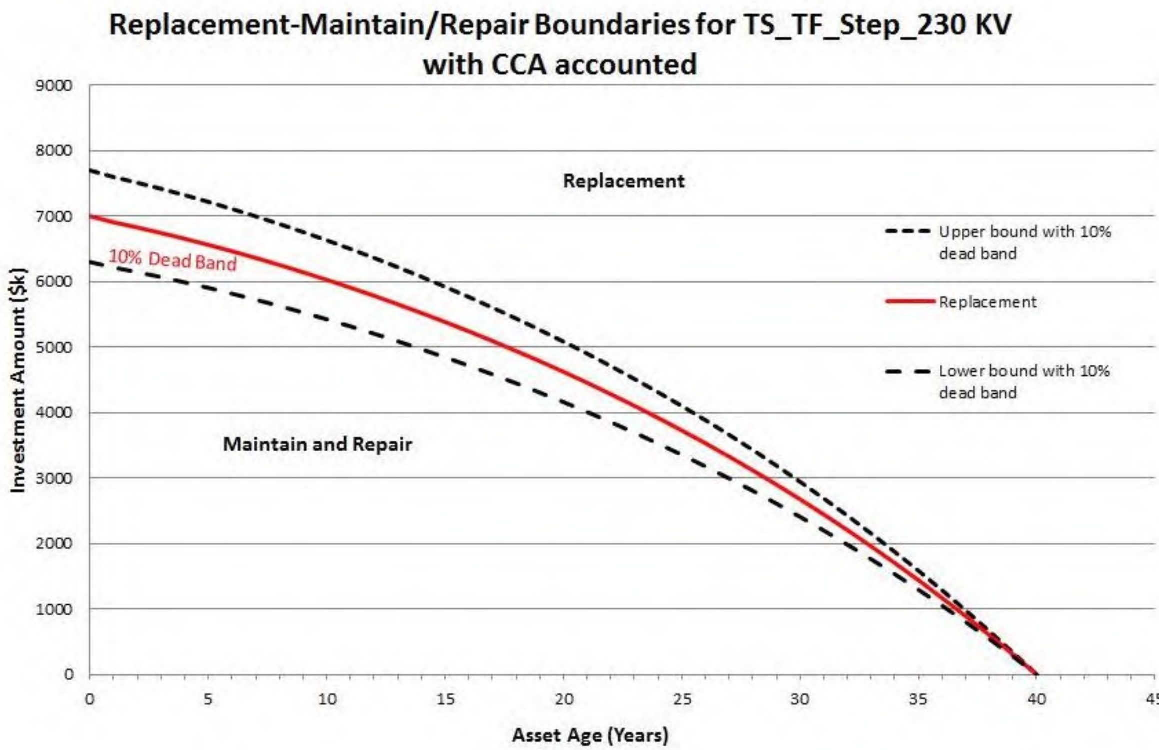

Replacement-Maintain/Repair Boundaries for TS_SW_GIS_500 kV
with CCA accounted
Replacement
10% dead band
Maintenance/Repair
Repair - Replace
Lower bound with
10% dead band
Upper bound with
10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
100
200
300
400
500
600
700
800
0
10
20
30
40
50
60


Replacement -Maintain/Repair Boundaries for TS_TF_Auto_230
with CCA accounted
Investment Amount ($k)
Asset Age (Years)
Replacement
Maintain and Repair
10% Dead Band
Upper bound with 10% dead band
Replacement
Lower bound with 10% dead band
0
2000
4000
6000
8000
10000
12000
0
10
20
30
40
50
60


Replacement-Repair/Maintain Boundaries for TS_TF_Auto_500
with CCA accounted
Replacement
10% dead band
Maintain and Repair
Upper bound with 10% dead band
Replacement
Lower bound with 10% dead band
Investment Amount ($k)
Asset Age (Years)
25000
20000
15000
10000
5000
0
0
5
10
15
20
25
30
35
40
45



Replacement-Maintain/Repair Boundaries for TS_TF_Stepdown_115
with CCA accounted
Replacement
10% Dead Band
Maintain and Repair
Replacement
Lower bound with 10% dead band
Upperbound with 10% dead band
Invsetment Amount ($k)
Asset Age (Years)
0
1000
2000
3000
4000
5000
6000
0
10
20
30
40
50
60
70


Replacement-Maintain/Repair Boundaries for TS_TF_Step_230 KV
with CCA accounted
Replacement
Maintain and Repair
10% Dead Band
Upper bound with 10% dead band
Replacement
Lower bound with 10% dead band
Investment Amount ($k)
Asset Age (Years)
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
0
5
10
15
20
25
30
35
40
45

Hydro One Limited/ Hydro One Inc.
Submission to the Board of Directors

Date: February 2, 2016

Re: Approval for Beck #2 Transformer Station Upgrade and Air Blast Circuit Breaker Replacement

At the board meeting, I will present a proposal to spend $93.2 million to replace twenty air-blast circuit breakers and other assets at the Beck #2 Transformer Station that are at end of life. The completed planned in-service date is December 2021.

We are asking for approval of the project, as per the attached board resolution.

Yours sincerely,

Sandy Struthers
Chief Operating Officer and
Executive Vice President, Strategic Planning

Beck #2 Transformer Station Upgrade

Resolution:

After consideration, upon motion duly made, seconded, and unanimously carried, be it RESOLVED:

THAT the Board of Directors of Hydro One Inc. approve the investment of $93.2 million for the Beck #2 Transformer Station Upgrade.

Hydro One Inc.

Hydro One Board of Directors

Approval – Beck #2 Transformer Station Upgrade and Air Blast Circuit Breaker Replacement

February 2, 2016

Overview

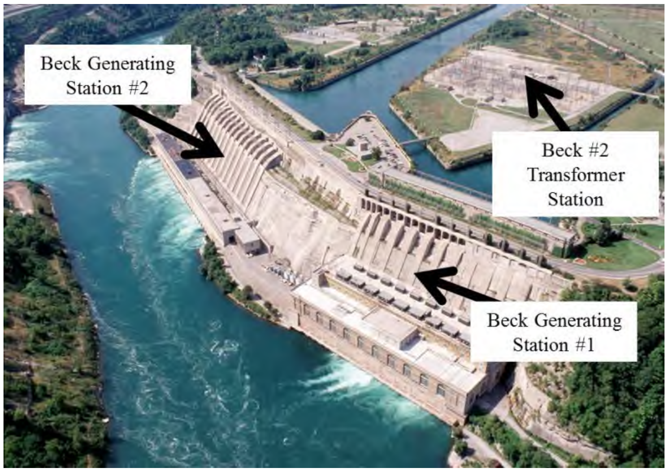
We are requesting approval for $93.2 million to replace 20 air-blast circuit breakers and complete other upgrades to Beck #2 Transformer Station.

This project employs the Company's comprehensive station upgrade strategy (versus individual component replacement) in order to reduce timelines, reduce frequency of required outages and provide maximum benefits to our customers at the most efficient cost.

All assets to be replaced have been assessed as being in poor condition as they are obsolete, significantly deteriorated or have reached the end of their useful life. In addition, they are contributing to higher costs to maintain and are negatively impacting the operability of the station and reliability to very significant customers, including Ontario Power Generation's hydro-electric generation stations, 2400 MW of customer load in Hamilton-Niagara region, and four interconnections with New York.

The final planned in-service date is December 2021 (6 year project), with elements of the project to be placed in service in the intervening period.

Investment Details



Beck #2 Transformer Station is located in Niagara Falls and was constructed in 1955. The station connects 1250MW Ontario Power Generation and is the termination point for eight 230 kV circuits and four interconnections with New York.

The condition of the assets at Beck has resulted in 68 air blast circuit breaker failures in the last 7 years, resulting in corrective and emergency work to address equipment deficiencies. Current annual sustainment cost of Beck #2 Transformer Station is $1 million, which is 2.5% of Hydro One Transmission's 2016 total power equipment preventative and corrective maintenance budget. This cost is forecasted to increase due to lack of spare parts and technical knowledge for maintaining this obsolete equipment. With this investment, we estimate that maintenance and corrective costs will be lowered by $600,000 per annum, and will further reduce incremental and indirect costs that the failures have caused for both Hydro One and our customers.

We are taking a brownfield upgrade approach, as it is significantly less expensive and is not complicated by the need to acquire real estate or obtain environmental approvals. Furthermore, this approach also enables us to place equipment in-service throughout the project. The station-centric approach taken also minimizes the number and duration of outages, as well as the total time to complete, as compared to replacing components over time.

Benefits

This investment will:
(a) Materially reduce maintenance and operational risks associated with operating end of life equipment at Beck #2 Transformer Station;
(b) Reduce ongoing station maintenance costs by $600,000 annually;
(c) Improve the transmission system reliability to 2400MW of load supply to customers in the Hamilton/Niagara area, 1250 MW of generation by Ontario Power Generation and the four inter-ties to New York; and
(d) Meet current Hydro One design standards and Northeast Power Coordinating Council requirements.

Cost Summary

This is a multi-year project, with expenditures planned over six years. However, we are able to segregate and measure discrete elements of the project to enable capital to be placed in service throughout the project duration, thus limiting the lag between capital spending and inclusion of the investment in the Company's rate base. Following is the planned schedule for placing assets in-service:

	≤ 2015	2016	2017	2018	2019	2020	2021	2022	Total
In-Service Additions	0	0	45.0	11.0	11.0	10.0	12.0	0.4	89.4

The cost estimate breakdown is as follows:

Category	Cost ($M)
Material	36.4
Construction	24.2
Project Management, Engineering & Commissioning	10.3
Contingency	6.9
Interest & Overhead	15.4
Total	**93.2**

This investment is supported by the completion to date of 25% of engineering and a detailed staging plan. The staging plan was reviewed with and agreed to by Ontario Power Generation. A key element of the staging plan is construction of a bypass to minimize the impact of equipment outages to Ontario Power Generation and customers in the Hamilton-Niagara region.

Alternatives Considered

New 230 kV Greenfield Switchyard Using Gas or Air-insulated Switchgear

Replacing the 230 kV switchyard with a new greenfield gas-insulated switchgear facility would minimize the outage availability concerns, improve the station short circuit interruption capability, improve the operability and equipment performance at the station and would result in an estimated $900k reduction in annual operation and maintenance costs. It also maximizes the flexibility for future Beck #1 Switching Station yard development.

The primary reason for not proceeding with this option is that the total cost is estimated to be $181 million, driving a material NPV difference to the selected alternative, which is not offset by other benefits. Furthermore, it would require expansion of Hydro One's station footprint onto Ontario Power Generation's limited available property. Additional environmental approvals would be required if the property is extended, lengthening the replacement timeline.

We also considered a greenfield switchyard with air insulated switchgear to further reduce footprint. This option, although less expensive, is still estimated at $163 million and was dismissed.

Regulatory Impacts

Capital expenditures for this project, of $25.3 million were included in Hydro One's approved 2015/2016 Transmission Rate Filing, based on a total project cost estimate of $32.7M and an in-service date of December 2016. Funding for the additional capital expenditure which was not included in the current approved transmission rate filing will be redirected such that there is no significant impact to committed in-service capital.

The 2017 to 2021 Transmission project capital expenditure will be included in the 2017/2018 rate application which will be filed with the Ontario Energy Board in May 2016. The significant increase in the project estimate from the 2015/16 Transmission Rate Filing is mostly due to the new strategy of completing work on a more efficient station-centric approach, which expands the scope of the current investment to consider the replacement or addition of other needed station components. The 2015/16 rate filing was based on a component replacement approach and did not include the incremental scope and associated benefits. We consider the risk of non-recovery of these amounts to be low as this is a more efficient and prudent approach to the investment.

This project impacts the operation of four international power lines. Modifications to the facility will require an application to the National Energy Board for approval of the work specific to the protection changes to those international power lines. An application will be filed with the National Energy Board in the first quarter of 2016.

No other regulatory issues are anticipated other than the standard need and prudence justification.

Risks and Mitigation

Outages

Obtaining agreement on the necessary outages at this station will be challenging given the impact to Ontario Power Generation, interconnections and the rest of the transmission system. Outages are considered to be a medium risk. Unforeseen delays in securing the required outages would directly impact on the construction cost and schedule.

We believe this risk has been mitigated by working with and obtaining agreement from impacted customers and stakeholders to develop a detailed staging plan, which includes the construction of a bypass and contingency plans to cover off normal operating conditions. Considering the length of this project, there is still a risk of construction delay due to unanticipated customer needs, however our assessment is that such delays would not be of a magnitude that would exceed the contingency amount.

Safety

The in-situ component replacement approach is inherently more dangerous than a greenfield construction due to working in close proximity to live equipment. This risk is considered to be medium.

This risk has been mitigated by developing a detailed outage staging plan and by employing Hydro One's existing safety processes and utility work protection code procedures which dictates work processes within close proximity of live equipment. High risk areas in the yard, due to issues such as tight clearances, have been identified and standard operating procedures for a live line environment will be enforced to address the safety risk.

First Nations

While most of the work is planned to be completed within the existing station footprint, a bypass line and a station expansion are likely required which will trigger a "screen out" under the Class Environmental Assessment under the Environmental Assessment Act. The screen out requires consultation with all those affected including surrounding First Nations. We will engage with the relevant First Nations as appropriate, and do not consider this element to be a high risk for this project.

Barrett Chute Switching Station: Demerger and End of Life Component Replacement

Overview of Recommended Alternative:

We are requesting approval for $21.6 million to replace deteriorated and end of life equipment as well as demerge and relocate Hydro One's facilities from the Ontario Power Generation powerhouse to its own new relay building that is to be built at Barrett Chute Switching Station. Including development expenditures to date, the total project cost is $25.3 million. This station has deteriorated assets and conditions that are negatively impact the reliability of supply to customers in the City of Kingston and surrounding Eastern Ontario.

Investment Details:

In-service: December 15, 2018

Barrett Chute switching station was originally placed into service in 1969. It is located in Eastern Ontario within Ontario Power Generation's Barret Chute Generating Station. The switching station connects 176MW of generation on the 115kV system.

Fire damage as a result of failed equipment at Barrett Chute SS

The existing six 115kV oil circuit breakers, its disconnect switches, protection, control and teleprotection equipment and other associated facilities are at end of life due to their poor condition, obsolescence and declining performance as verified through visual inspection, diagnostic testing and recent major interruption of October 27, 2015 which impacted 62MW of load in the City of Kingston as a result of failed equipment at the station. The asset event investigation recommended the earliest replacement of the oil circuit breakers and upgrades to the protection, control and teleprotection equipment in order to prevent this failure from reoccurring.

Historically, transmission and generation were designed, constructed and operated in a manner consistent with ownership. With the break-up of the former Ontario Hydro, assets were divided and demarcation points defined between Hydro One and Ontario Power Generation. The physical separation (demerger) of transmission and generation assets requires a substantial amount of effort. There are currently forty-four facilities with demerger potential. Outstanding agreements between the two companies require physical demerger when a significant project is initiate a by either company and when it makes business sense to do so.

Since all assets are located within the Barrett Chute Generating Station powerhouse; this investment will trigger a full demerger of assets between Hydro One and Ontario Power

Generation at this location. All Hydro One assets will be removed and new facilities will be installed in a new Hydro One relay building. Additional land will be required from Ontario Power Generation and the existing switchyard lease agreement will be modified to accommodate these new facilities.

Ontario Power Generation will contribute to the demerger costs of this project. Pursuant to the existing switchyard lease terms, Ontario Power Generation is obligated to pay the Landlord's Financial Contribution where Ontario Power Generation is accountable for a cost contribution as per the agreement to an aggregate maximum of approximately $642.5k. Ontario Power Generation will be invoiced after completion of the work as per the demerger agreement.

Benefits:

The investment will reduce the risk of customer interruptions by 75% through the elimination of equipment related outages.

Estimated Costs & In-service:

This is a multi-year project, with partial in-service additions in 2017 and 2018.

The cost breakdown is as follows:

Category	Cost ($M)
Project Management	0.6
Engineering	2.3
Material	8.7
Construction	5.0
Commissioning	2.0
Contingency	1.8
Interest & Overhead	4.2
Previous Expenditures	0.7
Total	**25.3**

The previous development approval of $3.7M was to carry out engineering, estimating and procurement of long lead time materials and the necessary engineering has been completed to achieve an estimate accuracy of +/-10%. The contingency is based solely on construction and commissioning to cover any deviation from the original design during execution.

This investment was included in the approved 2016 Budget with total project funding of $12.2M Additional required funding will be provided through the prioritization of investments within the approved Transmission Capital envelope and included in the 2017 Business Plan.

Other Alternatives Considered

Status Quo or Do nothing Alternative

Equipment at Barrett Chute SS, including breakers, switches and associated protection, control and teleprotection facilities are at end of life and in need of replacement. The Do Nothing option is rejected because it does not address asset conditions, the reliability and security of the station, and the risk of equipment failure.

Refurbish Assets in Barret Chute Powerhouse

Refurbishing the assets within Ontario Power Generation's powerhouse was rejected since it would not comply with the agreement between Hydro One and Ontario Power generation to demerger assets when possible. Furthermore, attempting to refurbish the assets in-situ would be more expensive and place the in-service at risk as it would require significant access rights from Ontario Power Generation.

Regulatory Considerations

The capital expenditures of $5.7M (2016) for the "Barrett Chute Switching Station: Demerger & Component Replacement" project are not included in the current Transmission Rate Application (EB-2014-0140) for 2016. Funding for the 2016 cost will be redirected from projects that are identified as being delayed or through the reprioritization of work within the approved Transmission capital envelope.

Capital expenditures of $11.7M (2017) and $7.9M (2018) for this project will be included in the Transmission Rate Application (EB-2016-0160) for 2017 and 2018.

Risks and Mitigation

First Nations and Metis Relations

Hydro One will notify the surrounding First Nations and Metis communities to maintain its ongoing positive relationship. Hydro One's Aboriginal Procurement Procedure, which promotes business development opportunities among aboriginal communities, will also be applied in the Request for Proposal to complete the project. Current risk is assessed to be low as Hydro One will notify in writing the surrounding First Nations and Metis Communities about the project and offer to meet. This approach has proven to be successful with respect to other similar projects.

This Approval ($M): 21.6	Previous Approval ($M): 3.7	Total Approval ($M): 25.3
Signature Block:		
Approved by: Karen Newman	Title: Vice President, Corporate Controller	Date: May 16/16
Approved by: Mike Penstone	Title: Vice President, Planning	Date: May 16/16
Approved by: Michael Vels	Title: Chief Financial Officer	Date: May 19/16

Appendix: Required information for SAP data input

Yearly Expenditures

	2016($M)	2017($M)	2018($M)	Total ($M)
Capital* and MFA	4.9	11.7	7.9	24.5
OM&A and Removals	0.8	-	-	0.8
Gross Investment Cost*	5.7	11.7	7.9	25.3
Recoverable	-	-	0.6	0.6
Net Investment Cost	5.7	11.7	7.3	24.7

*Includes capitalized interest and overhead at current rates

Rate base additions

	2017($M)	2018($M)	Total ($M)
In-Service $ Additions	5.7	18.8	24.5

In-service Date:	December 15, 2018
Business Case Summary #:	51000419
Appropriation Request #:	23394
Subject ID #	80815
Investment Driver:	N.T.C.1.45
Productivity Cards?	No
Director	Chong Kiat Ng
Planner	Donald Mastrangelo

<u>Scientific Research & Experimental Development Tax Credits (SR&ED):</u>
Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No

Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? No

Hydro One Limited / Hydro One Inc.
ADVICE OF DECISION OF BOARD OF DIRECTORS
(excerpt from minutes of Board of Directors)

to ______________________ date of meeting August 12, 2016

copies to: File agenda number 9.1

subject: Business Case for Approval

Martindale Transformer Station – T21/T23 and Component Replacement

After consideration, upon motion duly made, seconded, and unanimously carried, it was RESOLVED:

THAT the Board of Directors approve the investment of $75.8 million to refurbish the Martindale Transformer Station.

MWaukam
SECRETARY
Issued on August 16, 2016

Hydro One Limited/ Hydro One Inc.
Submission to the Board of Directors

Date: August 12, 2016

Re: Martindale Transformer Station: Autotransformer Replacement and Station Upgrade

We are seeking approval for an investment of $75.8 million to refurbish the Martindale transformer station. The investment is required to meet Ministry of the Environment and Climate Change requirements and to address the sustainment needs of the station. The project will be in-serviced in December 2021.

Yours sincerely,

Mike Penstone

Mike Penstone
Vice President, Planning

Martindale Transformer Station Replacement

Resolution:

After consideration, upon motion duly made, seconded, and unanimously carried, be it RESOLVED:

THAT the Board of Directors of Hydro One Inc. approve the investment of $75.8 million to refurbish the Martindale Transformer Station.

Hydro One Board of Directors

Approval – Martindale Transformer Station: Autotransformer Replacement and Station Upgrade Project

August 12, 2016

Martindale Transformer Station: Autotransformer Replacement and Station Upgrade

Summary of Recommendation:

We are requesting approval for $75.8 million to replace end-of-life autotransformers and complete other upgrades at Martindale Transformer Station on the existing property consistent with current Hydro One design standards and Northeast Power Coordinating Council requirements. The station has deteriorated assets and conditions that are negatively impacting the reliability of supply to local distribution companies, generators and large industrial customers in the City of Greater Sudbury and surrounding area.

Investment Details:

In-service: December 13, 2021

Martindale Transformer Station went into service in 1935. It is a 230 kV transformer station and major hub for East - West power flow on the 115kV transmission system in Northern Ontario. The station also supplies approximately 100MW to the City of Greater Sudbury, including the City's Wahnapitae Water Treatment Plant and connects large industrial mining customers to the transmission system, including Glencore Canada Corporation and Vale Canada Limited.

T21 autotransformer - 60 years old, end of life unit with no self cooling rating

This project will replace equipment at Martindale Transformer Station that is at end-of-life due to poor condition and performance, limited capacity, and obsolescence, and that poses a safety risk to field personnel due to electrical safety clearance issues. Since 2008, there have been a total of 32 cooling or oil level/temperature related issues on the T21 and T23 autotransformers and a total of 623 corrective and emergency work orders associated with all the equipment that is identified for replacement by this investment. These facilities will be replaced and upgraded to meet current Hydro One design standards and Northeast Power Coordinating Council requirements, including:

(i) two 230-115 kV, 75/100/125 MVA autotransformers (T21 and T23) that are at end of life, in poor condition, limited capacity and require noise mitigation;

64 year old, end of life 230kV oil circuit breaker

(ii) five 230kV Canadian Westinghouse GW oil circuit breakers that do not meet the required interrupting time for high voltage circuit breakers;

(iii) three 230 kV bus sections that are inadequate for withstanding the existing short circuit levels at the station;

(iv) four 115 kV line disconnect switches and two breaker disconnect switches;

(v) replacement of the 1960's vintage design 44kV switchyard equipped with eleven oil circuit breakers and four feeder tie switches that pose safety risks to field maintenance personnel due to electrical safety clearance issues;

Aerial of Martindale TS with locations of new facilities

(vi) upgrades to the DC Station service, protections, controls and telecom facilities to meet Northeast Power Coordinating Council requirements including A and B duplication and physical separation of protection systems;

(vii) upgrade spill containment system and install new noise barrier to comply with Ministry of the Environment and Climate Change requirements.

Hydro One has committed to the Ministry of the Environment and Climate Change to meet station noise compliance requirements and address noise complaints by installing a noise barrier for T25 and T26 transformers and replacing T21 and T23 autotransformers with quieter units. Furthermore, spill containment, drainage and oil/water separator facilities currently do not meet Ministry of the Environment and Climate Change requirements and are considered to pose the sixth greatest spill risk of the 291 Hydro One stations (other investments are ongoing or being planned to address the other high spill risk stations).

Other asset replacement strategies are also incorporated as part of this project to enable operational efficiencies. These other strategies include the replacement of end of life station insulators and high voltage instrument transformers as well as upgrades to station yard lighting, AC and DC station service systems and the station ground grid.

Benefits:

The investment will provide the following benefits:

a) improve transmission reliability performance by eliminating poor performing equipment and increase capacity by 15%;

b) reduce annual emergency and corrective maintenance orders at the station by 54% (70 orders) and reduce the associated costs by 41% (~$100k/year) through the elimination of end of life equipment.

c) eliminate electrical safety clearance issues in the 44kV switchyard;

d) comply with Ministry of the Environment and Climate Change requirements for an Environmental Compliance Approval by mitigating noise and spill risk at the station;

e) comply with Northeast Power Coordinating Council requirements including A and B duplication and physical separation of protections systems.

Estimated Costs & In-service:

This is a multi-year project, with partial in-service additions annually from 2017 to 2021.

The cost breakdown is as follows:

Category	Cost ($M)
Project Management	2.5
Engineering	5.7
Procurement	22.7
Construction	26.2
Commissioning	3.4
Contingency	4.3
Interest	0.9
Overhead	10.1
Total	75.8

Funds of $3.5 million were previously approved to carry out engineering, estimating and procurement of long lead time materials. The necessary engineering has been completed to achieve an estimate accuracy of +/-10%. The contingency is based solely on construction and commissioning to cover any deviation from the original design during execution.

This investment is included in the approved 2016 Budget and is included in the 2017-2022 business plan with total funding of $69.4M. The additional funding required will be redirected from other projects to enable overall capital expenditures to remain within the total approved envelope.

The incremental costs of 6.4 M$ were identified following a quality assurance review of the original estimate. The review identified that the scale of the civil work had been underestimated and shortcomings existed in the staging plan for the equipment outages required to execute the project.

The quality assurance review combined with more extensive outage planning and project scoping are actions that have been recently implemented as a result of assessments past projects.

Other Alternatives Considered

Status Quo or Do nothing Alternative

The status quo option is rejected because it does not address the poor condition of multiple end of life assets, including the capacity limiting autotransformers T21 and T23, the safety concerns associated with the 44kV switchyard electrical clearances, the negative impact on the transmission capacity and reliability, and does not address the non-compliance with Northeast Power Coordinating Council and Ministry of the Environment and Climate Change requirements.

Regulatory Considerations

Capital expenditures of $67.4 million for this project are included in the current Transmission Rate Application (EB-2016-0160) for 2017 and 2018 currently before the Ontario Energy Board for approval. This rate application assumed that all capital expenditures would be placed in-service at the end of 2020. The partial in-service strategy will create a $39 million variance from the rate base submitted to the Ontario Energy Board. The impact of this variance will result in other project's funding being reduced or reprioritized to ensure the 2017 and 2018 in-serviced capital aligns with allowable capital recovered through the revenue requirement.

Hydro One considers the risk of non-recovery of this investment, including the in-service and total cost variance, to be low because this investment will improve the quality and reliability of Hydro One's transmission system supplied by this station and will reduce future annual maintenance costs compared to current levels. The variances will be disclosed and defended at future transmission rate filing to the Ontario Energy Board at the appropriate time.

Risks and Mitigation

First Nations and Metis Relations

The work to be completed will take place within the existing station footprint and a Class Environmental Assessment is not required. However, Hydro One will notify the surrounding First Nations and Metis communities to maintain its ongoing positive relationship. Current risk is assessed to be low.

Appendix: Required information for SAP data input

This Approval ($M): 72.3	Previous Approval ($M): 3.5	Total Approval ($M): 75.8
Signature Block:		
Approved by: Mike Penstone	**Title:** Vice President Planning	**Date:**
Approved by: Karen Newman	**Title:** Vice President Corporate Controller	**Date:**
Approved by: Michael Vels	**Title:** Chief Financial Officer	**Date:**
Approved by: Mayo Schmidt	**Title:** President & CEO	**Date:**
Approved by:	*Board of Directors Advice*	**Date:**

Yearly Expenditures

$(M)	2016	2017	2018	2019	2020	2021	2022	Total
Capital* and MFA	3.5	21.1	15.5	15.9	10.3	3.7	1.5	71.5
OM&A and Removals	-	-	1.0	1.0	1.0	1.3	-	4.3
Gross Investment Cost*	3.5	21.1	16.5	16.9	11.3	5.0	1.5	75.8
Recoverable	-	-	-	-	-	-	-	-
Net Investment Cost	3.5	21.1	16.5	16.9	11.3	5.0	1.5	75.8

*Includes capitalized interest and overhead at current rates

Rate base additions

	2017($M)	2018 ($M)	2019 ($M)	2020 ($M)	2021 ($M)	Total ($M)
In-Service $	22.6	16.4	16.5	11.2	4.8	71.5

In-service Date:	December 13, 2021
Business Case Summary #:	51000177
Appropriation Request #:	23417
Subject ID #	81009
Investment Driver:	N.T.C.1.45
Productivity Cards?	No
Director	Chong Kiat Ng
Planner	Donald Mastrangelo

Scientific Research & Experimental Development Tax Credits (SR&ED):

- Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No

- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? No

SCHEDULE F

See attached examples of conductor sample testing reports verifying end-of-life condition and Business Cases for Line refurbishment:

- Circuit D1A
  - D1A/D3A – Line Refurbishment Program Business Case Summary
  - Estimate of Remaining Life of Conductors on Circuit D1A
- Circuit Q12S
  - Q11S/Q12S – Line Refurbishment Program Business Case Summary
  - Estimate of Remaining Life of Conductors on Circuit Q12S
- Circuit H24C
  - H24C – Line Refurbishment Program Business Case Summary
  - Estimate of Remaining Life of Conductors on Circuit H24C

Investment Driver: N.T.C.1.14 Date: February 19,2013

AR Number: 20899 Title: Transmission Line Refurbishment on D1A/D3A

Hydro One Networks - Business Case Summary - 50002930

Transmission Line Refurbishment on D1A/D3A

Investment Driver: **In-Service date:** December 15,2013

N.T.C.1.14 - Overhead Lines Refurbishment and Replacement Program - (2013 - $45.22M, 2014 - $127.87M)

Hydro One's transmission network consists of approximately 29,000 circuit km of overhead transmission lines. These transmission lines are used to transmit electric power, via integrated network and radial circuits, to either direct transmission customers or to transformation points connected to retail customers. The overhead lines refurbishment and replacement program (TC114) has been designed to refurbish lines approaching end-of-life.

This Approval: $5.8M **Previous Approval:** $0.1M **Project Total:** $5.8M

Need:

To address the deteriorating condition of conductors on the 115kV circuits D1A/D3A from St Johns Valley Jct to Decew Falls SS (4.24 km). Not proceeding with this investment will increase the probability of future line failures that will adversely impact the supply reliability and jeopardize public safety.

Investment Summary:

D1A/D3A is a double-circuit, 60 Hz, 115 kV transmission line that was built in 1943 on steel lattice towers. These circuits carry a maximum generation load of 166MW and serve as a critical supply to the area, including industrial customers (Georgia Pacific, ASW Steel).

Asset condition assessment activities have revealed that a number of line components are approaching end-of-life and approximately 4.24 km of transmission line requires refurbishment primarily due to conductor condition. This conductor is about 70 years old and conductor tests reveal that the tensile strength and ductility has deteriorated to the extent that it now requires replacement. Expected service life for conductors is approximately 70 years.

The proposed line refurbishment includes the section from structure 1 at Decew Falls SS to structure 16 at St Johns Valley Jct. The remaining sections of D1A/D3A circuits beyond St Johns Valley Jct have been either refurbished in previous years or do not require refurbishment at this point as they are in acceptable conditions. The proposed line refurbishment project will replace the conductor along with insulators and hardware, to bring the line to near new condition.

Results:

Improve public safety and maintain reliability by installing new conductors.

Costs:

	2013 M	2014 M	Total M
Capital* and MFA	5.6	0.1	5.7
OM&A and Removals	0.0	0.0	0.0
Gross Investment Cost*	5.6	0.1	5.8
Recoverable	0.0	0.0	0.0
Net Investment Cost	5.6	0.1	5.8

*Costs included AFUDC and Overheads at current rates

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Public safety and reliability would be compromised. Component failures require emergency restoration. This alternative was eliminated because it does not address increasing risks to public safety as the line crosses public roads/areas and reduced supply reliability to customers, including DeCew Falls Generation Station #1 and large industrial customers (ASW steel, Georgia Pacific).

Alternative One

605 kcmil conductor replacement on D1A/D3A

This alternative considers installation of 605 kcmil conductors on both D1A and D3A circuits. The existing conductors are 605 kcmil and 997 kcmil. This alternative was eliminated due to existing system needs.

Alternative Two

Like-for-Like Conductor replacement on D1A/D3A

This alternative considers like-for-like conductor replacement and necessary hardware associated with conductor replacement on the line section specified. The existing conductors are 605 kcmil and 997 kcmil. This alternative was eliminated as installation of different conductor sizes on each side of transmission line structures does not comply with current Hydro One design practices.

ALTERNATIVES CONSIDERED FURTHER

Alternative Three

997 kcmil conductor replacement on D1A/D3A

This alternative considers replacement of the conductor and necessary hardware associated with conductor replacement on the line section specified. The existing conductors are 605 kcmil and 997 kcmil. The existing conductors will be replaced by 997 kcmil conductor. This alternative includes replacement of the shieldwire and insulators. The scope of work also includes structure refurbishment as required. In addition, new inter-phase spacers will be installed on the circuits within specified sections.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative Three

Alternative 3 (997 kcmil Conductor replacement on D1A/D3A) is recommended because it mitigates reliability and safety risks associated with the aging and deteriorated conductor that is approaching end-of-life.

Investment Driver: N.T.C.1.14

AR Number: 20899

Date: February 19,2013

Title: Transmission Line Refurbishment on D1A/D3A

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt3**	**Comparison**
Reliability	HIGH	LOW	The conductors and line components are appoaching end-of-life and there is a high risk of failure with negative reliability consequences. Alt 3 addresses these risks.
Customer	N/A	N/A	Not influential in the investment decision.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	MED	LOW	New reliable equipment reduces probability of component failures and hence the safety risks as these circuits cross multiple public roads and residential areas.
Regulatory / Legal	MED	LOW	Lack of action to address the known poor condition of the existing conductor could result in regulatory and legal actions if a conductor failure was to occur.
Reputation	MED	LOW	The current situation will eventually cause forced outages with potential impact to corporate reputation.
Initial Cost ($M)		5.8	
Financial: PV Cost / NPV ($M)			NPV was not calculated as there is only one viable alternative and the decision was not primarily based on financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class B estimate from E&PD, which is accurate in the range of ± 20%, and includes a contingency for in-scope variances of $818k, which is 19% of the direct project cost.

Business Planning:

This project was included in the approved 2013-2017 Business Plan under accomplishment ID 4001 at a total cost of $3.23 M. Upon detailed estimating, a more accurate project cost of $5.83 M was estimated by E &PD. Funds will be redirected within budget envelopes for this project. Funding is available in the driver due to deferral of other projects.

Execution Risks:

Approvals - Low

EA - Low

S.92 - N/A

Outages - Med - There is currently an ongoing development project at Allanburg TS and some of the scheduled outages for the development project will be leveraged to carry out the line refurbishment work. As a result, there is a need to co-ordinate with outage changes on the development project.

Resourcing - Low

First Nations - Low

Real Estate - Low

Agreements - Low

Technology - Low

Investment Driver: N.T.C.1.14

AR Number: 20899

Date: February 19,2013

Title: Transmission Line Refurbishment on D1A/D3A

Regulatory Considerations:

This project involves end-of-life replacement work and will not increase capacity, thus an OEB Section 92 leave to construct application is not required. This project was included in the 2013/14 Transmission Rates application on ISD "S53" for $3.2M. No significant regulatory issues are anticipated other than standard need and prudence justification.

Funds Included in Business Plan: N	**Redirection Required:** N	**Planner:** Hassan Hamzeh
This Approval($M): 5.8	**Previous Approval($M):** 0.1	**Current Est. of Total Cost($M):** 5.8

Signature Block:

Submitted by: Wayne Smith	**Title:** SVP Planning & Operating	**Date:** 3 Apr '13
Reviewed by: Sandy Struthers	**Title:** Chief Administration Officer & CFO	**Date:** April 3/13
Recommended by: Peter Gregg	**Title:** Chief Operating Officer	**Date:** APR 4 - 2013
Approved by: Carmine Marcello	**Title:** President & CEO	**Date:** 4 4 13

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

To: Mr. H. Hamzeh
Hydro One Networks Inc.
483 Bay Street, North Tower, 15th Floor
Toronto, ON
M5G 2P5

ESTIMATE OF REMAINING LIFE OF CONDUCTORS ON CIRCUIT D1A

Kinectrics Report No: K-419037-RC-0003-R00
November 16, 2009

C. Dimnik
Transmission & Distribution Technologies Business

EXECUTIVE SUMMARY

Kinectrics Inc. carried out an analysis and assessment to estimate the minimum remaining life of the original 605 kcmil, 54/7 ACSR conductor on transmission line Circuit D1A between Hooper's Jct to St. Johns Valley Jct. The conductor was originally installed in 1943. One (1) conductor sample was retrieved between Structures 5 and 16 for testing and evaluation. Investment Planning of Hydro One Network Management has assumed this sample is typical of the condition along the line section and therefore the estimate of its' remaining life would be representative for the remainder of the line.

The estimate of minimum remaining life is based on a series of laboratory tests performed on the sample. The conductor had been in-service for about 66 years at the time of testing. Generally, the aluminum wires are moderately contaminated with light to moderate pitting. The steel wires show moderate to heavy surface rust with moderate to heavy pitting. The remaining tensile strength of the conductor is 87.9% of the rated tensile strength based on a breaking load test of the whole conductor and 88.1% based on breaking load tests on the individual wires. These results corroborate each other.

Based on Kinectrics' overall interpretation of the laboratory test results, assessments and analyses on the conductor sample obtained from Circuit D1A, the estimated minimum remaining life is **three (3)** years. The conductor should be able to remain safely in-service for this time without failure due to design wind and ice or vibration fatigue loads.

It is noted that the estimate of minimum remaining life is based on only one (1) sample that was assumed to be typical of the condition of the conductor along the entire line section. The confidence level would be higher if there were a greater number of samples tested. In addition, the details of the actual loading and weather conditions on circuit D1A are not fully known.

ESTIMATE OF REMAINING LIFE OF CONDUCTORS ON CIRCUIT D1A

Kinectrics Report No: K-419037-RC-0003-R00
November 16, 2009

C. Dimnik
Transmission & Distribution Technologies

INTRODUCTION

Many transmission lines in Ontario are well beyond their original accounting life (60 years) but have not yet reached their physical end of life. With increasing competitive pressures, it is becoming more important to assess the present day condition of aged transmission lines with the end objective to estimate the remaining life. Conductors are considered to be the critical component of transmission lines. This is because conductors identified for replacement initiates a Transmission Line Replacement and Refurbishment (TLR&R) project. This project then drives the assessment and replacement of other major components such as structures, insulators, hardware and grounding. Large capital expenditures can be deferred and life cycle asset management can be optimized if the remaining physical life of conductors can be estimated with reasonable accuracy and confidence.

The main objective of the assessment is to assign a minimum remaining life of the conductor based on its current physical condition. A discussion of remaining life of conductors is in Appendix A.

SAMPLES FOR LABORATORY TESTING

Quantity

The number of samples available for laboratory testing will affect the statistical significance of the results. The remaining life estimate is based on only one (1) sample that was assumed to be typical of the condition of the conductor along the entire line section.

Quality

This assessment determines the condition of an entire line section by examination of a very small sample length of the line. Site-specific conditions such as localized pollution sources are not known therefore cannot be taken into account. However, Hydro One Networks management considers that generally for line sections less than 20 km the average atmospheric contamination and corrosion conditions are assumed to be similar.

The location where the samples are taken within the line section and the location of the samples within the span are significant factors in whether the worst-case location has been selected.

To identify which areas of the province were more vulnerable to corrosion of conductors and other tower steel, a corrosivity map of Ontario was produced in the mid-late 1980's by Ontario Hydro Research Division. Since then, the atmospheric conditions have been influenced by many factors such as urbanization, government and industry regulations, the economy, etc. The map is out of date and should be updated. The estimate of minimum remaining life is based solely on the present condition of the conductor samples. A new atmospheric corrosion study would:

1) help determine the rate of deterioration,
2) help determine where to take other samples,
3) help understand the corrosion process and
4) help determine the source of the contaminants.

TEST SAMPLE FOR D1A

Circuit D1A extends approximately 6.70 km from Hooper's Jct to St. Johns Valley Jct. This section of the line was constructed in 1943 with 605 kcmil, 54/7 ACSR conductor. The conductor is constructed with 54 aluminum wires stranded in 3 layers over 7 galvanized steel wires. The conductor sample for testing was removed from the span between Structures 5 and 16. The conductor had been in-service for 66 years at the time it was removed. It is assumed that the condition of this sample is typical for this vicinity of the circuit.

The conductor has the following properties:

Size:	605 kcmil conductor
Stranding:	ACSR 54/7 (3 layers of aluminum wires, 2 layers of steel wires)
Wire Diameters:	Aluminium Wires: 0.1059 inches (2.69 mm)
	Steel Wires: 0.1059 (2.69 mm)
Rated Tensile Strength (RTS)	22,550 lbf (10,206 kgf)
Outer Diameter:	0.953 inches (24.21 mm)
Weight:	0.7790 lbf/ft (1.1593 kg/m)

The estimate of minimum remaining life is based on a series of laboratory tests performed on the one (1) sample taken from this circuit. The sample was obtained from the field with the suspension clamp still installed on the conductor. The sample was about 180 m in length on one side of the suspension clamp.

TEST OBJECTIVE

The objective of this study is to estimate the minimum remaining physical life of the conductor installed on Circuit D1A.

This is the fifteenth study for Hydro One using a variety of tests to estimate the remaining physical life of aged conductors. It is expected that some tests will contribute more than others. From earlier studies of the other lines, tests have been added, deleted or modified. Tests have been evaluated and chosen based on the type of deterioration and contamination for each situation. It is expected that the accuracy of estimating the remaining physical life should improve by establishing trends over a number of years.

TEST PROGRAM

The following tests were performed.

Conductor Tests

TEST NO.	TEST NAME	COMMENT
C1	Aeolian Vibration Endurance Test	On whole conductor sample
C2	Sheave Test	On whole conductor sample
C3	Breaking Load Test	On whole conductor sample

Individual Wire Tests

TEST NO.	TEST NAME	COMMENT
S1	Visual Examination	On Steel and Aluminum Wires
S2	Tensile Test on Individual Wires	On Steel and Aluminum Wires
S3	Torsional Ductility Test	On Steel and Aluminum Wires

TEST C1 - AEOLIAN VIBRATION ENDURANCE TEST

Objective

The objective of the Aeolian Vibration Endurance Test is to subject the aged conductor to relatively severe aeolian vibrations for an equivalent number of cycles that may be experienced in a 40-50 year design life. The test procedure is based on IEEE Std 1138-1994, *"IEEE Standard Construction of Composite Fiber Optic Overhead Ground Wire (OPGW) for Use on Electric Utility Power Lines"*. The test was originally developed to qualify OPGW against fatigue damage that may result from excessive levels of aeolian vibrations. Since the aluminum wires for OPGW and ACSR conductors are similar, the test is applicable to the conductor installed on Circuit D1A. The aluminium wires are vulnerable to fatigue damage. They will fail at suspension clamps, in-line splices, vibration dampers, spacer-dampers, marker balls, etc. It is very important that field samples include suspension clamps and in-line splices still installed on the conductor.

If it can be shown that the aged conductor can endure these laboratory vibrations after already experiencing many years of unknown field vibration, then the existing conductor in the field would be considered qualified to endure in-service aeolian vibrations for another 40-50 years. This test provides good confidence against fatigue failures.

Test Set-up and Procedure

The description of the set-up and procedure is in Appendix B.

Test Results

The result of the visual inspection of the tested sample is listed in Table 1.

Table 1 Results of Aeolian Vibration Endurance Test

Test Dates	Test Tension	Cycles	Amplitude	Frequency	Results
June 8 – July 9, 2009	32% RTS = 3,238 kgf (7,138 lbf)	100 million	Between 8.89 mm and 9.91 mm peak-to-peak	Between 29.194 Hz and 29.439 Hz	No visible signs of breaks or cracks of any the wires.

Criteria

If the aged samples are able to endure 100 million cycles without fatigue damage, then it can be concluded that the existing conductor can remain in-service for over forty (40) years without fatigue failure.

Conclusion

The results from the Aeolian Vibration Endurance Test indicate the existing D1A conductor can remain in-service for more than forty (40) years. This is noteworthy for estimating remaining life.

TEST C2 - SHEAVE TEST

Objective

The objective of the Sheave Test is to determine the ability of the conductor to withstand passing over a sheave a number of times without undesirable damage to the conductor. The test procedure is based on IEEE Std 1138-1994, *"IEEE Standard Construction of Composite Fiber Optic Overhead Ground Wire (OPGW) for Use on Electric Utility Power Lines"*

Conductor replacement involves using the existing, in-service conductor to pull in the new conductor. It is critical that the wires of the existing conductor pass through the sheaves without breaking. Broken wires separate from the body of the conductor and get entwined in the sheaves. In the worst case the conductor can break. At a minimum, the stringing operation will be interrupted and result in costly delays. Increased hazards to workers and the public are also a cause for concern.

Test Set-up and Procedure

The description of the set-up and procedure is in Appendix C.

Test Results

The sample tested had no other visible signs of breaks, cracks or failure of any the wires. The results of the Sheave Test are listed in Table 2.

Table 2 Results of Sheave Test

Test Date	Conductor Tension	Sheave Diameter	Angle over Sheave	Number Of Cycles	Results
July 20, 2009	32% RTS = 3,238 kgf (7,138 lbf)	713 mm (28 inch)	30.7º	35	Two (2) wires were broken after 20 cycles.

Criteria

If the aged samples are able to endure passing over a sheave 70 times after also experiencing 100 million cycles of simulated aeolian vibration without failure, then it can be concluded that the existing conductor can remain in-service for an equivalent lifetime.

Conclusion

The Sheave Test shows that the existing D1A conductor is likely to experience broken wires if used to pull in a new conductor in 40 years time.

TEST C3 - BREAKING LOAD TEST

Objective

The objective of this test is to determine the remaining breaking strength of the aged conductor and to compare this value to the rated tensile strength.

Test Results

The result of the breaking load data for the conductor is shown in the following table.

Conductor Sample	Remaining Breaking Strength	Percent of Rated Breaking Strength
Structure 5 – 16	8,976 kgf (19,789 lbf)	87.9 %

Criteria

Hydro One Networks has defined end of life when the remaining tensile strength of the conductor falls below 85% of the RTS. The exception to this is that if the remaining strength is below 85% then:

i) no other tests performed on the conductor can show unsatisfactory results and
ii) the maximum tension the conductor is subjected to in the field is less than 15% RTS

Conclusion

The results of the Breaking Load Test on the whole conductor sample indicates the D1A conductor to be in marginal condition.

TEST S1 - VISUAL EXAMINATION (Steel and Aluminum Wires)

Objective

The objective of this examination is to make a visual record of the surface condition of the conductor. This can be a very helpful indicator of the general condition of the conductor.

Test Procedure

The conductor was assessed using two (2) methods.

<u>Method 1</u> - The first method involved examining the same section of conductor that was used for the Tensile, Torsional Ductility, and Remaining Zinc Tests (see Tests S2, S3, and S4).
The test sample used was taken from about 20 m out from the suspension clamp. This section of conductor was considered to be a typical worst-case condition.

<u>Method 2</u> - The second method involved dissecting the conductor along a 180 m length, from the suspension out to its longest end. The aluminium wire layer was removed and the observations were centered around the condition of the steel layer and core wires. The steel wires were ranked according to their surface condition.

Test Results

The following table summarizes the results from the Method 1 dissection method.

<u>Method 1</u>

Method 1 Dissection Results

Conductor Sample	Component	Observation
D1A Structure 5 – 16, at 20 m from suspension	Aluminium Wires	<u>Outside Surface</u>: moderate contamination, see Figure 2 <u>Middle Layer</u>: heavy contamination, see Figure 3 <u>Inner Layer</u>: moderate to heavy contamination, see Figure 4
	Steel Core wires	33% to 66% covered with moderate rust and moderate pitting, see Figure 5

Method 2

The observations from the dissection and visual examination along the ½ span are contained in Appendix E. The results show that that steel core had some rust along the entire sample, even light rust noted under the suspension clamp. The extent and severity of rust varied along the sample length. The majority of the sample (84%) was rust covered (i.e. Stage 2c or 3). About 15% of the sample was between 33% and 66% rust covered (i.e. Stage 2b). The severity of rust ranged from light to heavy and the severity of pitting ranged from negligible to medium. Sections where the conductor was 100% covered in rust also showed the most severe rusting and pitting.

Criteria

Visual observations of high contamination, corrosion, cracked or broken wires would show that the surface of the conductor has deteriorated.

Conclusion

The degradation of the conductor has started to be noticeable. The amount of rust and contamination shows that the conductor is in the early stages of deterioration.

Figure 2 Outer Aluminum Wires
Circuit D1A, Conductor Structure 5 – 16

Figure 3 Middle Layer Aluminum Wires
Circuit D1A, Conductor Structure 5 – 16

Figure 4 Inner Layer Aluminum Wires
Circuit D1A, Conductor Structure 5 – 16

Figure 5a Steel Core Wires – Outer Surface
Circuit D1A, Conductor Structure 5 – 16

Figure 5b Steel Core Wires – Dissected
Circuit D1A, Conductor Structure 5 – 16

TEST S2 - TENSILE TEST (Steel and Aluminum Wires)

Objective

The objective of this test is to determine the remaining breaking strength of the aged conductor wires and to compare its value to the rated tensile strength of a new conductor.

Test Set-up

Four (4) aluminum wires from each layer and the seven (7) steel core wires were prepared from the conductor sample. The sample was about 40 cm in total length. The sample was put in the test machine so that there was greater than 30 cm distance between the grips.

The test sample used was taken from about 20 m out from the suspension clamp.

Test Procedure

The steel wire samples were preloaded to a value that was equal to an elongation of the sample of 0.10%. An extensometer was attached to the sample at the pre-load value to measure the elongation over a 250 mm gauge length. The extensionmeter was offset by 0.10% and the sample was loaded until 1.0% elongation was achieved. The load for 1.0% elongation was noted and the extensionmeter was removed. The load was increased again until failure.

Test Results

The details of the results of the Tensile Test on the individual wires are contained in Appendix D.

The calculated breaking strength of the conductor based on the tests on individual wires is listed in the table below.

Conductor Sample	Calculated Remaining Breaking Strength	De-rated Calculated Remaining Breaking Strength	Percent of Rated Breaking Strength (De-rated/Book Value)
D1A Structure 5 – 16, at 20m from suspension	21,225 lbf	19,828 lbf	88.1 %

The strength of the conductor is calculated from the sum of the strength of the individual steel and aluminum wires.

As stated in the Southwire ‘Overhead Conductor Manual’, the ‘rated breaking strength’ for an ACSR conductor is the sum of the strengths of the steel and aluminum wires multiplied by the appropriate stranding factor. This ‘de-rating‘ or stranding factor is mostly attributed to the stress concentrations that occur where the wires cross each other.

The ‘de-rated measured breaking strength’ of the conductor is the aggregate sum of the strengths of the individual steel wires measured at 1.0% elongation and the breaking load of the individual aluminum wires, multiplied by the appropriate stranding factor.

Criteria

Hydro One Networks has defined end of life when the remaining tensile strength of the conductor falls below 85% of the RTS. The exception to this is that if the remaining strength is below 85% then:

i) no other tests performed on the conductor can show unsatisfactory results and
ii) the maximum tension the conductor is subjected to in the field is less than 15% RTS

Conclusion

The de-rated remaining tensile strength of the sample based on the tensile test on the individual wires is less than 85% RTS. This value of remaining breaking strength is noteworthy for estimating remaining life.

TEST S3 – TORSIONAL DUCTILITY TEST (Aluminum and Steel Wires)

Objective

The objective of this test is to determine the number of torsional turns to failure for the steel wires. The complex stress-strain conditions that occur in the sample during the torsion test are sensitive to minor variations in surface condition and materials. This test is useful in assessing wire ductility under in-service loading.

Test Set-up

The length of sample is equal to 120 times the wire diameter plus the length required for clamping into the test machine. The sample is tensioned to 1% of the rated breaking strength of the wire.

The test sample used was taken from about 20 m out from the suspension clamp. This section of conductor was considered to be a typical worst-case condition.

Test Procedure

One clamp of the test machine remains stationary while the other rotates along the axis of the wire. The wire is twisted until it fails.

Test Results

The details of the results of the Torsional Ductility Tests on the individual wires are contained in Appendix D.

Four (4) aluminium wires from each layer and all seven (7) steel core wires were torsion tested. The turns to failure of the steel wire is listed in the table below.

Wire Number	Turns to Failure of Steel Wires
Wire 1	7.7
Wire 2	3.9
Wire 3	13.7
Wire 4	5.5
Wire 5	17.8
Wire 6	11.5
Core	9.9

Criteria

Hydro One Networks has defined end of life of the conductor if the average number of turns to failure of the individual steel wires (excluding the core wire) is below seven (7) turns and there are areas of excessive corrosion.

Conclusion

The average number of turns to failure of the steel wires was 10.0. There were two wires that failed below 7 turns. According to Hydro One criteria, the steel has not yet reached its end of life. It should also be noted that there is evidence of moderate corrosion. The average value for turns to failure is noteworthy for estimating remaining life.

SUMMARY AND DISCUSSION OF RESULTS

The following table summarizes the key result obtained from each test.

Test No.	Test Name	Key Result
C1	Aeolian Vibration Endurance Test	No visible signs of any breaks or cracks of any wires.
C2	Sheave Test	Two (2) broken wires.
C3	Breaking Load Test	Percent of RTS = 87.9%
S1	Visual Examination	The steel wires were 33% to 100% covered with moderate to heavy rust, with moderate to heavy pitting. The aluminum wires have moderate to heavy contamination with light to moderate pitting.
S2	Tensile Test of Individual Wires	Percent of RTS = 88.1% (De-rated compared to rated/book value)
S3	Torsional Ductility Test	Average of samples tested is 10.0 turns to failure. Two wires had fewer than 7 turns to failure.

The results from the **Aeolian Vibration Endurance Test** indicate that the conductor could endure at least another 40 years of vibration.

The results from the **Sheave Test** indicate that the conductor could have broken wires when used to pull in a new conductor after 40 years of vibration.

Without quantification, the results from the **Visual Examination** indicate that sections of the steel wires are in the middle stages of deterioration and have experienced a reduction in cross-sectional area

The **Torsional Ductility Test** average turns to failure of the 6 wire samples is 10.0, with two wires failing before 7 turns. According to Hydro One criteria, the steel has not yet reached its end of life. It should also be noted that there are areas of heavy surface corrosion.

The results from the **Breaking Load Test on the Whole Conductor** and confirmed by the **Tensile Tests on Individual Wires** indicate that the tensile strength of the conductors has been reduced. The reassessment of this conductor is important to form a trend to determine the current rate at which tensile strength is being lost.

CONCLUSION

Based on Kinectrics' overall interpretation of all the laboratory tests and assessments on the single conductor sample obtained from Circuit D1A, it is estimated that the conductor can remain safely in-service for at least another **three (3)** years from the date of testing without failure due to design wind and ice or vibration fatigue loads.

RECOMMENDATIONS

- It is recommended that a second minimum remaining life assessment on circuit D1A be performed as soon as possible within 3 years from the time of the assessment of the first sample. If the original conductor is replaced before a second assessment is performed, then the original conductor should be reassessed anyway. This will increase the understanding of the degradation process of ageing conductors and will subsequently lead to improving the accuracy of future assessments.
- It is recommended that an atmospheric study on contamination and effects on conductor be undertaken to update the study performed in about 1990 to determine the range of the rate of deterioration. This would determine whether atmospheric conditions have improved or worsened over the past decade and would be quite useful to estimate the present rate of deterioration of the conductors.
- It is recommended that a laboratory test program be initiated with the objective to improve the understanding and to characterise the deterioration process of ACSR conductors.

Prepared by: ______________________________
C. Dimnik
Engineer
Transmission and Distribution Technologies Business

Reviewed by: ______________________________
C. J. Pon
Principal Engineer
Transmission and Distribution Technologies Business

Approved by: ______________________________
R. Lings
General Manager
Transmission & Distribution Technologies Business

DISCLAIMER

Kinectrics Inc., has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and Hydro One Networks, dated January 19, 2001.

APPENDIX A
A DISCUSSION OF REMAINING LIFE OF CONDUCTORS

TECHNIQUES FOR SCREENING AGED CONDUCTORS AND SKYWIRES

The techniques presently used to screen aged conductors and skywires for more extensive testing are:

i) Torsional Ductility Test
ii) Tension Test
iii) Visual Examination to rate the surface condition of the galvanized steel wires.

These tests have been used for many years in Hydro One to assess the condition of conductors and skywires. Those determined to be in very poor condition are either scheduled for replacement or flagged for more detailed testing. Although this approach has been effective to identify conductors and skywires in need of replacement, the techniques do not estimate the remaining physical life of conductors. To improve the management of replacement of aged conductors, their remaining life must be estimated. Other test techniques and analyses also need to be developed.

A DISCUSSION OF REMAINING LIFE OF CONDUCTORS

To begin discussions on the issue of remaining life of aged conductors, it is necessary to have a common definition and an accepted approach to estimating remaining life. These can, and probably will, carry different meanings depending on perspective. From the perspective of a test laboratory, it is limited to assessing the physical condition of the conductor against various minimum physical criteria that represent end of life conditions. From a system planning or operating perspective, requirements may dictate that a conductor be replaced before the poor physical condition dictates.

End of physical life is defined when key conductor properties do not meet specified minimum requirements. These requirements are established either to withstand extreme in-service loading conditions or to meet industry or company standards.

Remaining physical life is defined as the number of years it takes the conductor to deteriorate to the specified minimum requirements. Remaining physical life is considered to be associated with the types of gradual deterioration that are due to long-term, continuous exposure to every day mechanical, environmental and electrical loads. These loads are generally viewed as systemic and widespread and apply to the entire line.

Remaining physical life does not relate to conductor deterioration that is due to singular or transient events such as lightning, gunshots, tornadoes, etc. These types of loads are usually limited to limited number of spans. Replacement of conductor in entire line sections is not normally required in these instances.

Estimating remaining physical life of conductors based on laboratory assessment involves i) gathering information using a variety of methods and ii) interpreting this information in an appropriate manner. Some methods, however, are designed more to determine whether an aged conductor can or cannot endure a specified load condition for a specified time. The information from these methods would be used more to estimate a minimum remaining life rather than an end of life.

Minimum remaining life is defined as the minimum number of years that a conductor should continue to meet or exceed the minimum requirements. It is worth noting that it is not necessary to estimate the end of physical life. This would require an estimate of when the conductor does not meet the minimum requirements. The uncertainty associated with expressing remaining life in terms of a minimum is much less than the uncertainty in attempting to estimate when the conductor actually reaches its end of life.

Categories of minimum remaining life are shown in Table 1. The values in the table recognise two (2) issues. First, there may be instances when the conductor being tested is judged not to meet the minimum requirements. In this case, the conductor should be scheduled for replacement within the next three (3) years. Second, the number of categories of minimum remaining life must be realistic considering the inherent variability in the conductor condition, the present level of technology and information and what is really useful for managing the asset. If the conductor does meet the minimum requirements, then the minimum remaining life of the conductor is assigned as either greater than 3, 10 or 20 years.

Table 1 Categories of Estimates of Minimum Remaining Life

	Years			
Remaining Life	<3	>3	>10	>20

Generally, reassessing the conductor at some reasonable point in the future after the initial assessment will help establish the rate of conductor deterioration and will provide updated information to revise the estimate of minimum remaining life.

APPENDIX B
DESCRIPTION OF AEOLIAN VIBRATION TEST

Test Set-up and Apparatus

The set-up for the Aeolian Vibration Test is shown in Figure B-1.

The conductor was contained between two intermediate abutments. The active span cable length was about 26 m and the passive span cable length was about 12 m for a total cable length of approximately 38 m between the load pins of the deadend clamps. Fixed end abutments were used to load and maintain tension in the cable. As per IEEE Std 1138, the conductor was tensioned to 3,238 kgf or 25% of the conductor's RTS (12,950 kgf). This was applied using a cantilever weight arm on one of the end abutments.

The deadend assemblies were installed between the intermediate abutments. The original suspension assembly was supported at a height such that the static sag angle of the cable to horizontal was about 1.5 degrees in the active span and about 3.0 degrees in the passive span.

The free loop antinode amplitude of the cable was measured at the second free loop from the suspension assembly towards the shaker. An electronically controlled shaker was used to excite the cable in the vertical plane. The shaker armature was securely fastened to the cable so that it was perpendicular to the cable in the vertical plane.

Test Procedure

The initial target vibration frequency was 34.29 cps, which is the frequency produced by a 4.5 m/s wind (i.e., frequency = 830 ÷ diameter of the conductor in mm). The actual vibration frequency was the system resonance that was nearest to the target frequency and also provided good system stability.

Normally, the target free loop peak-to-peak antinode amplitude would be 8.07 mm or one third of the conductor diameter.

The conductor was subjected to 100 million vibration cycles. On completion of the aeolian vibration test, the suspension clamp was removed and the outer aluminum wires were inspected for damage. Before removing the outer wires to inspect the steel wires, the conductor was subjected to a Sheave Test described in the next section.

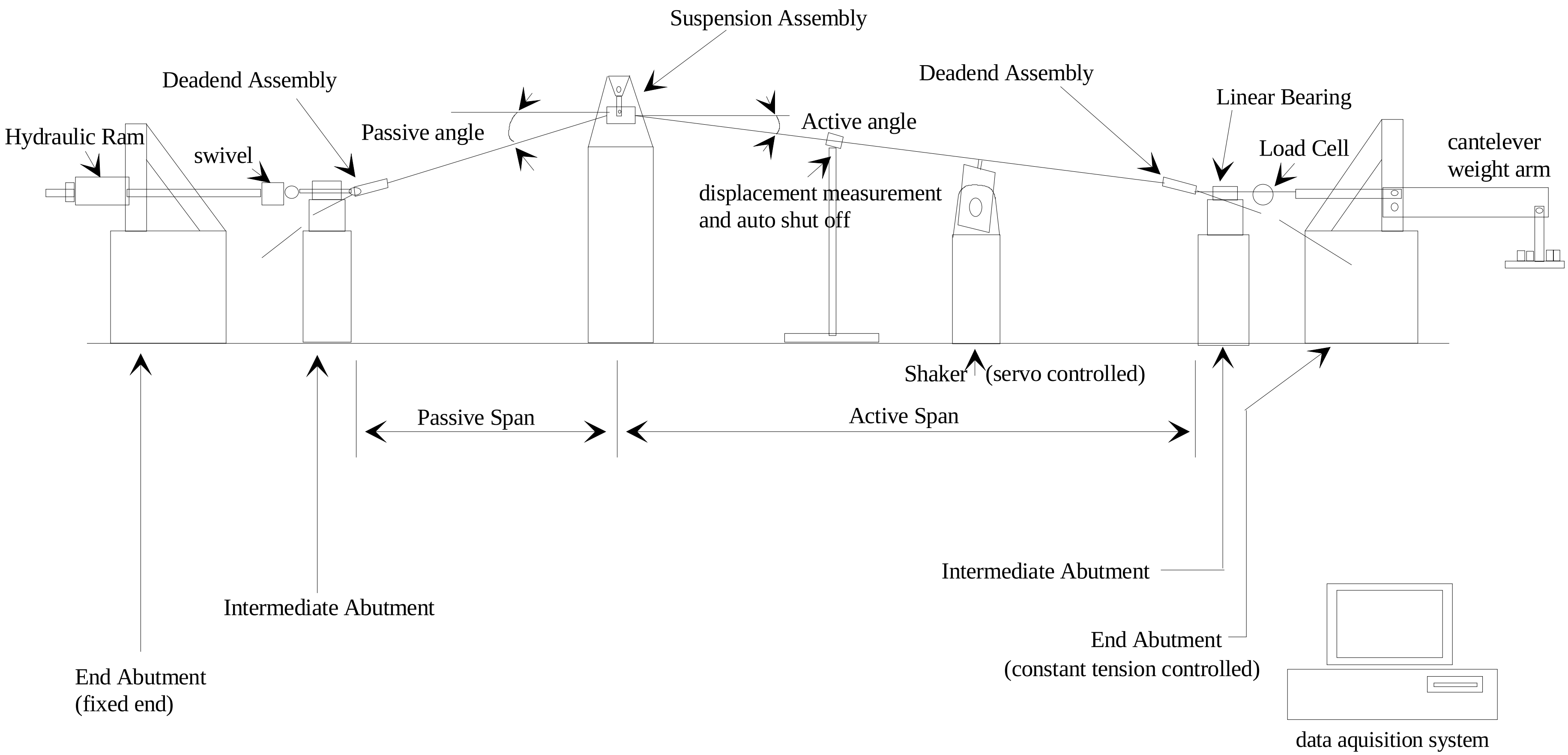


Figure B1   Set-Up for Aeolian Vibration Test

APPENDIX C

DESCRIPTION OF SHEAVE TEST

Test Set-up

The set-up for the Sheave Test is shown in Figure C-1.

Test Apparatus

The length of cable between the deadends load pins was approximately 12 m. The target tension of the cable was 3,238 kgf or 32% of the cable RTS (10,206 kgf). The inside diameter of the sheave was 713 mm. The total angle of the cable over the sheave was 30.7°. The set-up allowed 2.5 m of cable to travel through the sheave at a speed of 0.122 m/sec. A load cell was installed at one end to measure the tension in the cable.

Test Procedure

A two and a half (2.5) meter length of the cable sample was pulled 70 times forward and backward over the sheave (i.e. 35 times each way). The section of cable that passed over the sheave included the area where the suspension clamp was located.

The dissection and visual examination of the cable components within the two and a half (2.5) meter test section were performed after the test.

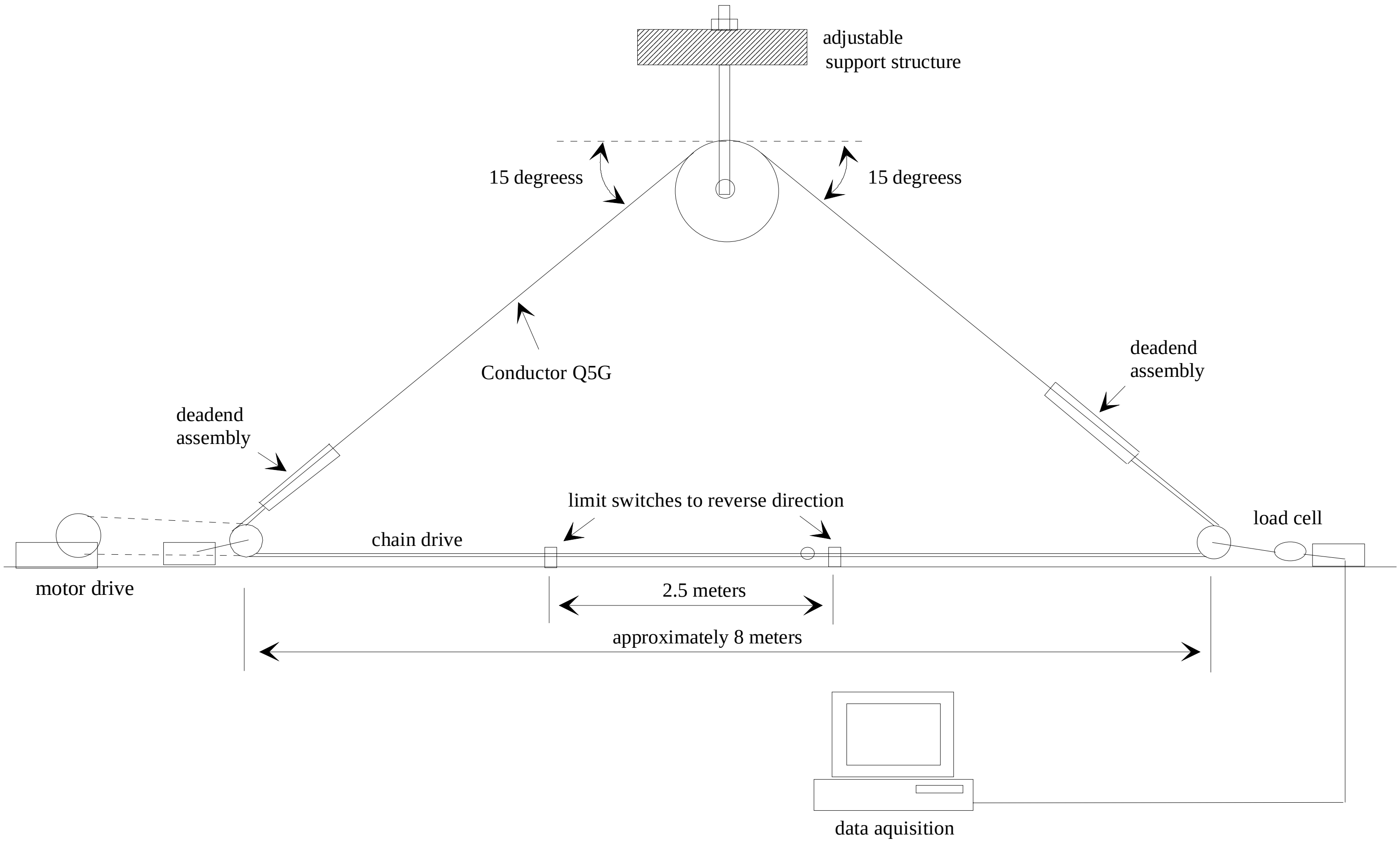


Figure C1 Set-up for Sheave Test

APPENDIX D

TENSION AND TORSION TESTS
ON ACSR CONDUCTOR FROM CIRCUIT D1A

To : **Mr. Hassan Hamzeh,** Hydro One Networks Inc. Kinectrics Report No.: K-419037-RC-0003-R00 Issue Date : July 24, 2009

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 605.0 kcmil 54/7

KINECTRICS

TEST DATE : July 21-23, 2009 TESTED by : Claudiu ILINA KINECTRICS REF. NO. : C - 2009 - 03

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	ZONE LOCATION	REMOVED FIELD DATE	RECEIVED DATE
D1A	Unknown	Unknwown	Unknown	-	24-Nov-09

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 605.0 kcmil 54/7 Nom. Cable Diameter ** : 0.953 in Measured Cable Diameter : 0.966 in

	Alum. Outer Layer		Alum. Middle Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Nom. Breaking Strength of	26,000 psi	Nom. Breaking Strength of	26,000 psi	Nom. Breaking Strength of	205,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1059 in	single wire = 229 lbf	0.1059 in	single wire = 229 lbf	0.1059 in	single wire = 229 lbf	0.1059 in	Nom Breaking Strength of single wire = 1,806 lbf
Area of Wire :	0.0088 sq. in		0.0088 sq. in		0.0088 sq. in		0.0088 sq. in	Nom. Load @ 1% Elongation = 1,629 lbf
Number of Wires in Layer :	24		18		12		7	For Tension Test Load @ 1% Elongation **** :
Number of Wires Tested :	4		4		4		7	Preload = 255 lbf., Offset = 0.010 in.
Tension Load for Torsion Test * :	3.29 lbf = 1.492 kgf		3.29 lbf = 1.492 kgf		3.29 lbf = 1.492 kgf		19.06 lbf = 8.644 kgf	
Torsion Test sample length * :	15.21 in = (120 x dia.+ 2.5")		15.21 in = (120 x dia.+ 2.5")		15.21 in = (120 x dia.+ 2.5")		15.21 in = (120 x dia.+ 2.5")	

TEST RESULTS

Measured Wire Diameter : Outer 0.1055 in; Middle 0.1075 in; Inner 0.1070 in; Steel .107 (less pitting) & 0.116 (pitting are

	Alum. Outer Layer			Alum. Middle Layer			Alum. Inner Layer			Steel and Core Wires				Remaining Zinc[3] % Zinc (avg of wires 1-6) vs. Core Wire
Surface	The outer surface of the alum. wires had :			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	Contam	Pitting	Color	Category [1]	Rating [2]	Rust	Pitting	
	Medium	Medium	Dark Grey	Heavy	Light	Dark Grey	Medium - Heavy	None	Dark Grey	2b	3	Medium	Medium	See Note A

Comments (Alum. Outer Layer) : The outer surface Medium dark grey contam and pitting The inner surfaceMedium dark grey contamination

Comments (Alum. Middle Layer) : The outer surface Heavy dark grey contamination The inner surface Heavy dark grey contamination

Comments (Alum. Inner Layer) : The outer surface Medium-heavy dark grey contamination The inner surface dark grey contamination. Brown marks from steel rust

Comments (Steel and Core Wires) : The outer surface Medium rust and pitting The inner surface Very light white contamination in one side The core wire Medium rust and medium - light pitting

WIRE No.	Outer: Number of Turns	Outer: Breaking Strength lbf	Outer: Breaking Strength psi (calc)	Middle: Number of Turns	Middle: Breaking Strength lbf	Middle: 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	47.7	209	23,728	63.7	185	21,003	61.8	199	22,593	7.7	1557	1831	207,877
2	44.9	200	22,706	65.4	208	23,615	56.9	215	24,409	3.9	1405	1583	179,721
3	48.8	218	24,750	72.2	199	22,593	58.7	210	23,842	13.7	1403	1515	172,001
4	51.4	195	22,139	59.9	199	22,593	66.0	197	22,366	5.5	1486	1704	193,458
5	-	-	-	-	-	-	-	-	-	17.8	1390	1652	187,555
6	-	-	-	-	-	-	-	-	-	11.5	1394	1566	177,791
7 (core wire)	-	-	-	-	-	-	-	-	-	9.9	1635	1953	221,728
Average (Steel & Core 'No. of Turns' is Avg. 1 to 6)	**48.2**	**206**	**23,331**	**65.3**	**198**	**22,451**	**60.9**	**205**	**23,302**	**10.0**	**1,467**	**1,686**	**191,447**
Avg. Strength x # of Wires in Layer :	(A)	**4,932 lbf**		(B)	**3,560 lbf**		(C)	**2,463 lbf**					
Total Strength of (Aluminum/Steel) :					A+B+C=(D)	**10,955 lbf**					(E)	**11,804 lbf**	
Calculated Total Strength of Layer :	(F)	**5,496 lbf**		(G)	**4,122 lbf**		(H)	**2,748 lbf**			(J)	**12,640 lbf**	
Measured / Calculated (%) :	A/F =	**89.7%**		B/G =	**86.3%**		C/H =	**89.6%**			E/J =	**93.4%**	
Total Load on Steel @ 1% Elongation :										(K)	**10,270 lbf**		
Total Measured Breaking Strength :					D+K=(L)	**21,225 lbf** = **94.3% of Book Value.**							
Derated Meas. Breaking Strength****					(M)	**19,828 lbf** = **88.1% of Book Value.**							
Rated Breaking Strength ** (book value) :					(N)	22,500 lbf							

- Shaded areas indicate data manually entered or calculated.

See Page 2 for Test Methods and Specifications. See Page 2 for asterisk (*) and footnote explanations.

Note A : REMAINING ZINC TEST PERFORMED ON 'CATEGORY 1, RATING 1' STEEL WIRES ONLY. **Note : Please see 'Private Information' on Page 3.** Revision 2009-10

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 605.0 kcmil 54/7

TEST DATE : July 21-23, 2009 TESTED by : Claudiu ILINA KINECTRICS REF. NO. : C - 2009 - 03

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	ZONE LOCATION	REMOVED FIELD DATE	RECEIVED DATE
D1A	Unknown	Unknwown	Unknown	-	24-Nov-09

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 605.0 kcmil 54/7 Nom. Cable Diameter ** : 0.953 in

	Alum. Outer Layer		Alum. Middle Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Nom. Breaking Strength of single wire = 229 lbf	26,000 psi	Nom. Breaking Strength of single wire = 229 lbf	26,000 psi	Nom. Breaking Strength of single wire = 229 lbf	205,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1059 in		0.1059 in		0.1059 in		0.1059 in	Nom Breaking Strength of single wire = 1,806 lbf
Area of Wire :	0.0088 sq. in		0.0088 sq. in		0.0088 sq. in		0.0088 sq. in	Nom. Load @ 1% Elongation = 1,629 lbf
Number of Wires in Layer :	24		18		12		7	For Tension Test Load @ 1% Elongation **** : Preload = 255 lbf., Offset = 0.01 in.
Number of Wires Tested :	4		4		4		7	
Minimum Elongation in 10", at Failure, in Percent (%) : * **	1.5 %		1.5 %		1.5 %		3.5 %	

TEST RESULTS

WIRE No.	Elongation in 10 " at Failure		Elongation in 10 " at Failure		Elongation in 10 " at Failure		Elongation in 10 " at Failure	
	Measurement (inches)	Percent %	Measurement (inches)	Percent %	Measurement (inches)	Percent %	Measurement (inches)	Percent %
1	10.13	1.3	10.13	1.3	10.11	1.1	10.43	4.3
2	10.10	1.0	10.12	1.2	10.10	1.0	10.35	3.5
3	10.13	1.3	10.11	1.1	10.13	1.3	10.22	2.2
4	10.11	1.1	10.09	0.9	10.13	1.3	10.40	4.0
5	-	-	-	-	-	-	10.50	5.0
6	-	-	-	-	-	-	10.29	2.9
7 (core wire)	-	-	-	-	-	-	10.69	6.9
Average :	**10.12**	**1.2 %**	**10.11**	**1.1 %**	**10.12**	**1.2 %**	**10.37**	**4.1 %**

- Shaded areas indicate data manually entered or calculated.

Tension & Elongation Test Method : ASTM B557-02a for Aluminum wires & ASTM A370-03a 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 B230-99 Table 1, and for Steel wires from ASTM B498-98 Table 4.
**** Values for 1% Elongation from CSA CAN3-C49.6-M85, Table 2.
***** Derating values from Southwire Overhead Conductor Manual, Table 1-14.
Note 1 : During measurement, wire broke outside the extensiometer gauge marks, unable to obtain an elongation value.

[1] 'Category' from Table 2, Page 3, Hydro One Category.
[2] 'Rating' from Table 3, Page 3.
[3] 'Remaining Zinc' from Table 1 (H), Page 3.

Revision 2009-10

NOTE : Please see "Private Information" note on Page 3.

ACSR 605.0 kcmil 54/7, CCT : D1A, Line Section : Unknown, Structure No.: Unknwown

TABLE 1

Remaining Zinc on Steel and Core Wires									
	Measured Data				Calculated Data				
Wire No.	Wgt. of Wire Before Stripping (g) (A)	Min. Dia. Before Stripping (mm) (B)	Wgt. of Wire After Stripping (g) (C)	Min. 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	REMAINING ZINC TEST PERFORMED ON "CATEGORY 1, RATING 1" STEEL WIRES ONLY.								
2									
3									
4									
5									
6									
Avg. of 1 to 6									
7 (core wire)									

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/6030 kg/m³ 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		
Hydro One Category	Kinectrics Category	Percent of Rust by Area
1	Stage 1	none (0 %)
2	Stage 2 a	>0 - 33 %
3	Stage 2 b	33 - 66 %
4	Stage 2 c	66 - <100 %
5	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	Medium surface rust with mild pitting
4	Heavy surface rust with mild to medium pitting
5	Heavy surface rust with medium 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: Craig Pon

C. Pon
Principal Engineer
Transmission & Distribution Technologies

DISTRIBUTION (By E-mail)			E-Mail Address
Mr. H. HamzehMr.	Network Asset Management, TCT15	(plus one (1) hard copy by mail)	hassan.hamzeh@HydroOne.com
S.B. Woodward	Network Asset Management, TCT15		s.b.woodward@HydroOne.com
Mr. J. Dedlow	Network Asset Management, TCT15		john.dedlow@HydroOne.com

PRIVATE INFORMATION

APPENDIX E

RESULTS OF VISUAL EXAMINATION – TEST NO. S1, METHOD 2. DISSECTION ALONG ITS ENTIRE LENGTH ON ACSR CONDUCTOR FROM CIRCUIT D1A

Distance from Suspension	Extent of Rust					Severity of Rust					Comments
	Stage					Rating					
meters	1	2a	2b	2c	3	1	2	3	4	5	
180				X				X			> 66% of section covered with medium rust, mild pitting
177.5					X				X		100% of section covered with heavy rust, medium pitting
175					X				X		100% of section covered with heavy rust, medium pitting
172.5					X				X		100% of section covered with heavy rust, medium pitting
170					X				X		100% of section covered with heavy rust, medium pitting
167.5					X				X		100% of section covered with heavy rust, medium pitting
165					X				X		100% of section covered with heavy rust, medium pitting
162.5					X				X		100% of section covered with heavy rust, medium pitting
160					X				X		100% of section covered with heavy rust, medium pitting
157.5					X				X		100% of section covered with heavy rust, medium pitting
155					X				X		100% of section covered with heavy rust, medium pitting
152.5					X				X		100% of section covered with heavy rust, medium pitting
150					X				X		100% of section covered with heavy rust, medium pitting
147.5					X				X		100% of section covered with heavy rust, medium pitting
145					X				X		100% of section covered with heavy rust, medium pitting
142.5					X				X		100% of section covered with heavy rust, medium pitting
140					X				X		100% of section covered with heavy rust, medium pitting
137.5					X				X		100% of section covered with heavy rust, medium pitting
135					X				X		100% of section covered with heavy rust, medium pitting
132.5					X				X		100% of section covered with heavy rust, medium pitting
130					X				X		100% of section covered with heavy rust, medium pitting
127.5					X				X		100% of section covered with heavy rust, medium pitting
125					X				X		100% of section covered with heavy rust, medium pitting
122.5					X				X		100% of section covered with heavy rust, medium pitting
120					X				X		100% of section covered with heavy rust, medium pitting
117.5					X				X		100% of section covered with heavy rust, medium pitting
115					X				X		100% of section covered with heavy rust, medium pitting
112.5					X			X			100% of section covered with medium rust, mild pitting
110					X			X			100% of section covered with medium rust, mild pitting
107.5				X			X				>66% of section covered with light rust
105				X			X				>66% of section covered with light rust
102.5				X			X				>66% of section covered with light rust
100				X				X			>66% of section covered with medium rust, mild pitting
97.5				X				X			>66% of section covered with medium rust, mild pitting
95			X				X				33%-66% of section covered with light rust
92.5			X				X				33%-66% of section covered with light rust
90			X					X			33%-66% of section covered with medium rust, mild pitting
87.5			X					X			33%-66% of section covered with medium rust, mild pitting
85.0				X				X			>66% of section covered with medium rust, mild pitting
82.5				X				X			>66% of section covered with medium rust, mild pitting
80.0			X				X				33%-66% of section covered with light rust
77.5			X				X				33%-66% of section covered with light rust
75.0			X					X			33%-66% of section covered with medium rust, mild pitting
72.5				X			X				>66% of section covered with light rust
70.0			X				X				33%-66% of section covered with light rust
67.5			X				X				33%-66% of section covered with light rust
65.0			X				X				33%-66% of section covered with light rust
62.5			X					X			33%-66% of section covered with medium rust, mild pitting
60.0				X				X			>66% of section covered with medium rust, mild pitting
57.5				X				X			>66% of section covered with medium rust, mild pitting

Distance from Suspension	Extent of Rust					Severity of Rust					Comments
	Stage					Rating					
meters	1	2a	2b	2c	3	1	2	3	4	5	
55.0				X				X			>66% of section covered with medium rust, mild pitting
52.5				X				X			>66% of section covered with medium rust, mild pitting
50.0											Repair splice
47.5											Repair splice
45.0					X				X		100% of section covered with heavy rust, medium pitting
42.5					X				X		100% of section covered with heavy rust, medium pitting
40.0					X				X		100% of section covered with heavy rust, medium pitting
37.5					X				X		100% of section covered with heavy rust, medium pitting
35.0					X				X		100% of section covered with heavy rust, medium pitting
32.5					X				X		100% of section covered with heavy rust, medium pitting
30.0					X				X		100% of section covered with heavy rust, medium pitting
27.5					X				X		100% of section covered with heavy rust, medium pitting
25					X			X			100% of section covered with medium rust, mild pitting
22.5				X				X			>66% of section covered with medium rust, mild pitting
20				X				X			>66% of section covered with medium rust, mild pitting
17.5				X				X			>66% of section covered with medium rust, mild pitting
15				X				X			>66% of section covered with medium rust, mild pitting
12.5				X				X			>66% of section covered with medium rust, mild pitting
10				X			X				>66% of section covered with light rust
7.5			X				X				33%-66% of section covered with light rust
5.0					X		X				100% of section covered with light rust
2.5				X			X				>66% of section covered with light rust
0		X					X				Suspension Clamp Location. <33% covered with light rust
2.5				X			X				>66% of section covered with light rust
5.0					X			X			100% of section covered with medium rust, mild pitting
7.5					X			X			100% of section covered with medium rust, mild pitting
10.0					X			X			100% of section covered with medium rust, mild pitting
12.5					X				X		100% of section covered with heavy rust, medium pitting
15.0					X			X			100% of section covered with medium rust, mild pitting
17.5					X			X			100% of section covered with medium rust, mild pitting
20.0					X			X			100% of section covered with medium rust, mild pitting

Category	% Rust by Area on Outer Surface of Steel Wires	Rating	Severity of Rust on Outer Surface of Steel Wires
Stage 1	none (0 %)	1	No Rust, 100% galvanized
Stage 2 a	>0 - 33 %	2	Light surface rust and negligible pitting
Stage 2 b	33 - 66 %	3	Medium surface rust with mild pitting
Stage 2 c	66 - <100 %	4	Heavy surface rust with mild to medium pitting
Stage 3	100%	5	Heavy surface rust with medium to heavy pitting

DISTRIBUTION

Mr. H. Hamzeh (2)	Hydro One Networks 483 Bay Street, North Tower, 15th Floor Toronto, ON M5G 2P5
Mr. C.J. Pon (1)	Transmission and Distribution Technologies, KB223

Investment Driver: N.T.C.1.12

AR Number: 22869

Date: August 14, 2015

Title: Q11S/Q12S, Beck # 1 SS x Glendale TS - Line Refurbishment

Hydro One Networks - Business Case Summary - 50004140

Q11S/Q12S, Beck # 1 SS x Glendale TS - Line Refurbishment Program

Investment Driver: **In-Service date:** December 2016

N.T.C.1.12 - Overhead Lines Component Refurb & Replacement - (2015- $109.9M, 2016-$89.8M, 2017-$134.0M)

Hydro One's transmission network consists of approximately 29,000 circuit kilometres of overhead transmission lines. Programs within this driver have been designed to meet reliability expectations, regulatory and legal requirements, and to minimize safety impacts associated with failure of various transmission line components.

This Approval: $17.4M **Previous Approval:** $0 **Cost Total:** $17.4M

Need:

To address the deteriorating condition of conductor, steel structures, shieldwire and all associated hardware on the 115 kV circuits Q11S/Q12S from Glendale TS x Beck #1 SS. These circuits are essential to supply several large customers and facilitate up to 174 Megawatts of power transmission from Sir Adam Beck Generating Station # 1. Not proceeding with this investment will increase risk to reliability, public safety and customer satisfaction due to expected line equipment outages.

Investment Summary:

Q11S/Q12S, from Sir Adam Beck #1 SS to Glendale TS is a 115kV double circuit transmission line supplying power from Sir Adam Beck #1 Generating Station. The overhead line crosses the QEW and 405 highway, several major roads, a public golf course and the Welland Canal. The 13 km proposed section refurbishment was built in 1922 and contains 58 steel structures.

This investment is driven by end of life conductor which has been determined by tested conductor samples. These tests have shown that the conductor has failed to meet the minimum required torsional ductility, tensile strength and corrosion level. Laboratory tests measured a torsional ductility of 3.2 vs. the minimum required 5 turns and a rated breaking tensile strength of 83 vs. the minimum required 85 percent. Visual conductor core examination determined that severe corrosion of the core has occurred. In addition to replacing the conductor, the line is brought back to like new condition by replacing all hardware, insulators and shieldwire and refurbishing all structures and foundations. Hydro One also requires a fibre cable to be installed on this line section to provide communication infrastructure to meet Hydro One's teleprotection requirements.

This investment funds the line refurbishment of 13 double circuit kilometers on circuits Q11S and Q12S, Glendale TS x Beck #1 SS. The refurbishment includes the replacement of the end of life conductor, steel structure members, line hardware and insulators. The existing shieldwire will be replaced with optical fibre composite overhead ground wire.

Results:

Improved reliability, public safety and customer satisfaction and reduce risk of regulatory fines or sanctions by replacing transmission line components at or near End of Life.

Costs:

	2015 M	**2016** M	**2017** M	**Total** M
Capital* and MFA	1.5	13.9	1.5	16.9
OM&A and Removals	0.5	0.0	0.0	0.5
Gross Investment Cost*	2.0	13.9	1.5	17.4
Recoverable	0.0	0.0	0.0	0.0
Net Investment Cost	2.0	13.9	1.5	17.4

*Includes interest and overhead at current rates

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Continue to operate Q11S/Q12S in current condition. Not proceeding with this investment will result in an increased risk of overhead line component failure. Overhead line component failure will reduce system reliability and increase the risk to public safety.

Alternative One

Completely Rebuild the Overhead Transmission Line, Q11S/Q12S, Glendale TS x Sir Adam Beck #1 SS.
The result of this investment on Q11S/Q12S will improve the performance of the line and increase the reliability, public safety and customer satisfaction. This investment would completely rebuild the existing line on the existing right of way and replace all components and structures with new conductor, hardware, insulators, shieldwire and towers. This alternative was rejected for 3 main reasons. First, the outage requirement would be significantly longer to build a new line in place of the existing line and is unlikely to be approved. Second, the cost for this option is about 2 times higher than the cost of a line refurbishment, the preferred alternative, while not affording any material benefit in reliability, public safety, customer satisfaction or regulatory/legal compliance. Third, this alternative requires 1 additional year to implement in order to allow approval of a class Environmental Assessment necessary for a complete line rebuild.

ALTERNATIVES CONSIDERED FURTHER

Alternative Two

Refurbish the Overhead Transmission Line, Q11S/Q12S, Glendale TS x Sir Adam Beck #1 SS.
The result of this investment on Q11S/Q12S will improve the performance of the line and increase the reliability, public safety and customer satisfaction. This investment will facilitate the replacement of all end of life conductors, insulators and hardware. All structures will be refurbished as required. The new conductor layout will meet the current 'Overhead Line Clearance Standard, LD-51000-002-R0, section 4.1.3 Existing Lines'. This standard specifies a vertical clearance requirement of 0.9 m above CSA standards when replacing existing conductor with new conductors. The shieldwire will be replaced by OPGW between Glendale TS x Sir Adam Beck # 1 SS to facilitate telecom protection requirement for Niagara Area.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative Two

Alternate two is recommended because this investment on Q11S/Q12S will improve the performance of the line and increase the reliability, public safety and customer satisfaction.

Alternatives Compared

	Investment Level Risk		
Business Value	**Current Risk**	**Alt2**	**Comparison**
Reliability	HIGH	LOW	From 2010-2014 there has been 1 sustained outage due to a failed insulator on the Q11S/Q12S. Given the deteriorated condition of the conductor, there is an increased level of urgency to refurbish this asset to minimize long duration sustained line outages in the future. Alternative 2 is expected to improve reliability performance by replacing line components in poor condition prior to failure causing outages.
Customer	MED	LOW	Given the deteriorated condition of the conductor, there is an increased level of urgency to refurbish this asset to minimize customer interruptions which will help to increase customer satisfaction. Alternative 2 is expected to reduce the customer risk to low by replacing line components prior to failures causing customer interruptions. The customers fed directly by these circuits are Niagara on the Lake Hydro, Horizon Utilities, Welland Weir CGS, General Motors and Ontario Power
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	MED	LOW	Given the deteriorated condition of the conductor, there is an increased level of urgency to refurbish this asset to minimize the risk to public safety. This line crosses major roads, a golf course and the Welland Canal. Alternative 2 is expected to reduce the safety risk to low by replacing line components in poor condition prior to failures that may pose risks to public safety.
Regulatory / Legal	MED	LOW	Regulatory fines or sanctions may occur in the future if the line refurbishment is not completed due to overhead line component failures that may lead to circuit outages and pose a risk to public safety. Alternative 2, is expected to reduce this risk to low by reducing overhead line component outages.
Reputation	N/A	N/A	Not influential in the investment decision.
Initial Cost ($M)		17.4	
Financial: PV Cost / NPV ($M)			NPV was not calculated as there is only one alternative and the decision was not primarily based on financial factors.

Investment Risk and Mitigation:

Cost:
The estimate is based on unit cost estimates, which is accurate in the range of +/-50%. This strategy is based on the premise that the aggregate average of multiple line refurbishments under this program will converge towards the unit cost. The key assumptions for this investment are that the existing clearances are adequate and that there are no exceptional construction access challenges.

Business Planning:
This investment is included in the 2015-2019 Business Plan as a line refurbishment program placeholder. The funds required to complete this work will be redirected from this placeholder and stay within the Transmission Capital envelope.

Execution Risks:
Approvals Risk Level: NA

S.92 Risk Level: NA - A Section 92 application is not required for this transmission line refurbishment because the End of Life conductors will be replaced with a replacement conductor that meets HONI's latest design best practices. The overall rating of the circuit will not be increased as a result of this work.

EA Risk Level: NA - An Environmental Assessment is not required for this transmission line refurbishment work as there will be less than 25 structure replacements.

Outages Risk Level: Medium - Obtaining outages on the Q11S/Q12S circuits is difficult as they are critical to facilitating the supply of generation from Sir Adam Beck #1 to the transmission system. This risk is being mitigated by the long term planning and coordination between OPG, Hydro One and customers fed off the circuits, specifically, Horizon, GM and Niagara on the Lake. Communicating Hydro One's plan and adapting to customer needs is instrumental in staging this investment successfully. This coordination is being led by Hydro One Operating.

Resourcing Risk Level: Low - Hydro One's Engineering, Project Management and Construction expect to able to complete the entire scope of work by the required in-service year of 2016.

First Nations and Métis Relations Risk Level: Low - First Nations may require time to meet with Hydro One to understand this investment and ensure that their interests are being taken into consideration.

Real Estate Risk Level: NA

Agreements Risk Level: NA

Technology Risk Level: NA

Regulatory Considerations:
$17.1M of the Transmission capital expenditures for the 'Q11S/Q12S Beck #1 SS x Glendale TS Line Refurbishment investments included in 2016 of the OEB approved 2015/16 Tx Rate Filing (EB-2014-0140) as part of Lines Sustainment Capital and specifically within ISD- S54 'Q11S/Q12S Line Refurbishment'.

This lines refurbishment investment involves a capital replacement of the lines and associate components in line with Hydro One Engineering's current standard practice and will not trigger a Section 92 application.

No significant regulatory issues are anticipated other than the standard need and prudence justification.

Investment Driver: N.T.C.1.12

Date: August 14, 2015

AR Number: 22869

Title: Q11S/Q12S, Beck # 1 SS x Glendale TS - Line Refurbishment

Funds Included in Business Plan: N	**Director:** Chong Kiat Ng	**Planner:** Michael Medeiros
This Approval($M): 17.4	**Previous Approval($M):** 0	**Current Est. of Total Cost($M):** 17.4

Signature Block:		
Submitted by: Mike Penstone	**Title:** Vice President Planning	**Date:** Aug 18/15
Reviewed by: Michael Vels	**Title:** Chief Financial Officer	**Date:** 8/18/15
Recommended by: Sandy Struthers	**Title:** COO & EVP Strategic Planning	**Date:** Aug 18/15
Approved by: Carmine Marcello	**Title:** President & CEO -EC Member	**Date:**

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

To: Hassan Hamzeh
Sustainment Investment Planning
Hydro One Networks Inc.
483 Bay Street, North Tower, 15th Floor
Toronto, Ontario
M5G 2P5

ESTIMATE OF REMAINING LIFE OF CONDUCTORS ON CIRCUIT Q12S
Kinectrics Inc. Report No.: K-419527-RC-0004-R00
June 2, 2014

Dmitry Ladin, Michael Colbert, Greg Brown
Transmission and Distribution Technologies Business

EXECUTIVE SUMMARY

Kinectrics Inc. carried out an analysis and assessment to estimate the remaining life of the original conductor installed in 1920s on the transmission line section, Circuit Q12S. One (1) conductor sample was retrieved from the line for testing in October 2013. The tower numbers have been identified as No. 32-33 in the shipping documentation. Investment Planning of Network Management has assumed the sample is typical of the condition along the line section and therefore the estimate of its remaining life would also be typical for the remainder of the line.

The estimate of remaining life is based on a series of laboratory tests performed on the one (1) sample. The ACSR (Aluminum Conductor Steel Reinforced) conductor has been in-service for approximately 80 years at the time of testing. Generally, the aluminum wires exhibit moderate to heavy contamination and pitting. The steel wires, however, exhibit in many sections light to moderate corrosion on outside surfaces. The remaining tensile strength of the conductor is 93.4% of the rated tensile strength based on a breaking load test on the whole conductor and 83.4% based on individual strands.

Based on Kinectrics' overall interpretation of the laboratory test results, assessments and analyses on the conductor sample obtained from Circuit Q12S, the estimated minimum remaining life is **less than three (3)** years. The reduced tensile strength from the rated tensile strength is a significant factor in assigning this life. The conductor should be able to remain safely in-service for this time without failure due to design wind and ice or vibration fatigue loads.

The remaining life estimate is based on only one (1) sample that was assumed to be typical of the condition of the conductor along the entire line section. The confidence level would be higher if there were a greater number of samples tested. In addition, the details of the actual loading and weather conditions on circuit Q12S are not fully known.

REMAINING LIFE ASSESSMENT OF CONDUCTORS ON CIRCUIT Q12S

Kinectrics Inc. Report No.: K-419527-RC-0004-R00

June 2, 2014

Dmitry Ladin, Michael Colbert, Greg Brown
Transmission and Distribution Technologies Business

INTRODUCTION

Many transmission lines in Ontario are well beyond their original accounting life (60 years) but have not yet reached their physical end of life. With increasing competitive pressures, it is becoming more important to assess the present day condition of aged transmission lines with the end objective to estimate the remaining life. Conductors are considered to be the critical component of transmission lines. This is because conductors identified for replacement initiates a Transmission Line Replacement and Refurbishment (TLR&R) project. This project then drives the assessment and replacement of other major components such as structures, insulators, hardware and grounding. Large capital expenditures can be deferred and life cycle asset management can be optimized if the remaining physical life of conductors can be estimated with reasonable accuracy and confidence.

TECHNIQUES FOR SCREENING AGED CONDUCTORS AND SKYWIRES

The techniques presently used to screen aged conductors and skywires for more extensive testing are:

i) Torsional Ductility Test
ii) Tension Test and Elongation
iii) Visual Examination to rate the surface condition of the galvanized steel wires.

These techniques have been used for many years in Hydro One (formerly part of Ontario Hydro) to assess the condition of conductors and skywires. Those conductors determined to be in poor condition are either scheduled for replacement or flagged for more detailed testing. Although this approach has been effective to identify conductors and skywires in need of replacement, the techniques do not estimate the remaining physical life of conductors. To improve the management of replacement of aged conductors, their remaining life must be estimated based on other tests and analyses.

A DISCUSSION OF REMAINING LIFE OF CONDUCTORS

To begin discussions on the issue of remaining life of aged conductors, it is necessary to have a common definition and an accepted approach to estimating remaining life. These can, and probably will, carry different meanings depending on perspective. From the perspective of a test laboratory, it is limited to assessing the physical condition of the conductor against various minimum physical criteria that represent end of life conditions. From a system planning or operating perspective, requirements may dictate that a conductor be replaced before the poor physical condition dictates.

End of physical life is defined when key conductor properties do not meet specified minimum requirements. These requirements are established either to withstand extreme in-service loading conditions or to meet industry or company standards.

Remaining physical life is defined as the number of years it takes the conductor to deteriorate to the specified minimum requirements. Remaining physical life is considered to be associated with the types of gradual deterioration that are due to long-term, continuous exposure to every day mechanical, environmental and electrical loads. These loads are generally viewed as systemic and widespread and apply to the entire line.

Remaining physical life does not relate to conductor deterioration that is due to singular or transient events such as lightning, gunshots, tornadoes, etc. These types of loads are usually limited to limited number of spans. Replacement of conductor in entire line sections is not normally required in these instances.

Estimating remaining physical life of conductors based on laboratory assessment involves i) gathering information using a variety of methods and ii) interpreting this information in an appropriate manner. Some methods, however, are designed more to determine whether an aged conductor can or cannot endure a specified load condition for a specified time. The information from these methods would be used more to estimate a minimum remaining life rather than an end of life.

Minimum remaining life is defined as the minimum number of years that a conductor should continue to meet or exceed the minimum requirements. It is worth noting that it is not necessary to estimate the end of physical life. This would require an estimate of when the conductor does not meet the minimum requirements. The uncertainty associated with expressing remaining life in terms of a minimum is much less than the uncertainty in attempting to estimate when the conductor actually reaches its end of life.

Categories of minimum remaining life are shown in Table 1. The values in the table recognise two (2) issues. First, there may be instances when the conductor being tested is judged not to meet the minimum requirements. In this case, the conductor should be scheduled for replacement within the next three (3) years. Second, the number of categories of minimum remaining life must be realistic considering the inherent variability in the conductor condition, the present level of technology and information and what is really useful for managing the asset. If the conductor does meet the minimum requirements, then the minimum remaining life of the conductor is assigned as either greater than 3, 10 or 20 years.

Table 1 Categories of Estimates of Minimum Remaining Life

	Years			
Remaining Life	<3	>3	>10	>20

Generally, reassessing the conductor at some reasonable point in the future after the initial assessment will help establish the rate of conductor deterioration and will provide updated information to revise the estimate of minimum remaining life. The assessment on Circuit Q12S is one of numerous comprehensive testing and analysis undertaken of aged ACSR/Copper conductors. Circuits E1C, A11N, Q2AH and A8G were the first few conductors assessed. Establishing trends are very important in understanding and quantifying the ageing process of these conductors.

SAMPLES FOR LABORATORY TESTING

Quantity

The number of samples available for laboratory testing will affect the statistical significance of the results. The remaining life estimate is based on only one (1) sample that was assumed to be typical of the condition of the conductor along the entire line section.

Quality

This assessment determines the condition of an entire line section by examination of a very small sample length of the line. Site-specific conditions such as localized pollution sources are not known therefore cannot be taken into account. However, Hydro One Networks management considers that generally for line sections less than 20 km the average atmospheric contamination and corrosion conditions are assumed to be similar.

The location where the samples are taken within the line section and the location of the samples within the span are significant factors in whether the worst-case location has been selected.

It should be noted that a recent analysis of the atmosphere in the vicinity of the line has not been done. The estimate is based solely on the present condition of the conductor samples. An atmospheric corrosion study would:

1) help determine the rate of deterioration,
2) help determine where to take other samples,
3) help understand the corrosion process and
4) help determine the source of the contaminants.

TEST SAMPLE FOR Q12S

Circuit Q12S was built in the 1920s. The conductor has the following properties:

Size:	605 kcmil conductor
Stranding:	ACSR 54/7
Wire Diameters:	0.1059 inches (2.69 mm)
Rated Tensile Strength (RTS)	22,500 lbf (10,206 kgf)
Outer Diameter:	24.2 mm (0.953 inches)
Weight:	0.7790 lbf/ft

The estimate of minimum remaining life is based on a series of laboratory tests performed on the one (1) sample taken from this circuit. The sample was obtained from the field with the suspension clamp still installed on the conductor. The sample was about 120 m in length, as measured from the suspension clamp out to the ½ span end.

It is assumed that the condition of this sample is typical for the circuit. The tower numbers have not been identified in shipping documentation. This line was installed in the 1920s and therefore the conductor had been in-service for more than 80 years at the time of testing.

TEST OBJECTIVE

The objective of this study is to estimate the minimum remaining physical life of the conductor installed on Circuit Q12S.

This is a study using a wide variety of tests to estimate the remaining physical life of aged conductors. It is expected that some tests will contribute more than others. From earlier studies of the other lines, tests have been added, deleted or modified. Tests have been evaluated and chosen based on the type of deterioration and contamination for each situation. It is expected that the accuracy of estimating the remaining physical life should improve by establishing trends over a number of years.

TEST PROGRAM

The following tests were performed.

Conductor Tests

TEST NO.	TEST NAME	COMMENT
C1	Aeolian Vibration Endurance Test	On whole conductor sample
C2	Sheave Test	On whole conductor sample
C3	Breaking Load Test	On whole conductor sample

Individual Wire Tests

TEST NO.	TEST NAME	COMMENT
S1	Visual Examination	On Steel and Aluminum Wires
S2	Tensile Test on Individual Wires	On Steel and Aluminum Wires
S3	Torsional Ductility Test	On Steel and Aluminum Wires

TEST C1 - AEOLIAN VIBRATION ENDURANCE TEST

Objective

The objective of the Aeolian Vibration Endurance Test is to subject the aged conductor to relatively severe aeolian vibrations for an equivalent number of cycles that may be experienced in a 40-50 year design life. The test procedure is based on IEEE Std. 1138-1994, *"IEEE Standard Construction of Composite Fiber Optic Overhead Ground Wire (OPGW) for Use on Electric Utility Power Lines"*. The test was originally developed to qualify OPGW against fatigue damage that may result from excessive levels of aeolian vibrations. Since the aluminum wires for OPGW and ACSR conductors are similar, the test is applicable to the conductor installed on Circuit Q12S. The aluminum wires are vulnerable to fatigue damage. They will fail at suspension clamps, in-line splices, vibration dampers, spacer-dampers, marker balls, etc. It is very important that field samples include suspension clamps and in-line splices still installed on the conductor.

If it can be shown that the aged conductor can endure these laboratory vibrations after already experiencing many years of unknown field vibration, then the existing conductor in the field would be considered qualified to endure in-service aeolian vibrations for another 40-50 years. This test provides good confidence against fatigue failures.

Test Set-up and Procedure

The description of the set-up and procedure is shown in Appendix A.

Test Results

The result of the visual inspection of the tested sample is listed in Table 1.

Table 1 Results of Aeolian Vibration Endurance Test

Circuit	Test Dates	Cycles	Amplitude	Frequency, Hz	Results
Q12S	February 27 – April 18, 2014	100 million	7.9 mm peak-to-peak	35.7 – 44.4	No visible signs of breaks or cracks of any of the wires.

Criteria

If the aged samples are able to endure 100 million cycles without fatigue damage, then it can be concluded that the existing conductor can remain in-service for over forty (40) years without fatigue failure.

Conclusion

The results from the Aeolian Vibration Endurance Test indicate the existing Q12S conductor can remain in-service for more than forty (40) years. This is noteworthy for estimating remaining life.

TEST C2 - SHEAVE TEST

Objective

The objective of the Sheave Test is to determine the ability of the conductor to withstand passing over a sheave a number of times without undesirable damage to the conductor. The test procedure is based on IEEE Std. 1138-1994, *"IEEE Standard Construction of Composite Fiber Optic Overhead Ground Wire (OPGW) for Use on Electric Utility Power Lines"*

Conductor replacement involves using the existing, in-service conductor to pull in the new conductor. It is critical that the wires of the existing conductor pass through the sheaves without breaking. Broken wires separate from the body of the conductor and get entwined in the sheaves. In the worst case the conductor can break. At a minimum, the stringing operation will be interrupted and result in costly delays. Increased hazards to workers and the public are also a cause for concern.

Test Set-up and Procedure

The description of the set-up and procedure is shown in Appendix B.

Test Results

The section of the cable with the broken aluminum wires was excluded from Sheave Test setup because the localized conductor damage was too severe to allow unrestricted conductor passes through the sheave wheel.
The sample tested had no other visible signs of breaks, cracks or failure of any the wires. The results of the Sheave Test are listed in Table 2.

Table 2 Results of Sheave Test

Circuit	Conductor Tension	Sheave Diameter	Angle over Sheave	Number Of Cycles	Results
Q12S	2,041 kgf (4,500 lbf)	713 mm (28 inch)	31.2º	35	No visible signs of breaks or cracks of any of the wires.

Criteria

If the aged samples are able to endure passing over a sheave 70 times after also experiencing 100 million cycles of simulated aeolian vibration without failure, then it can be concluded that the existing conductor can remain in-service for an equivalent lifetime.

Conclusion

The result of the Sheave Test provides confidence that the existing Q12S conductor could pull in a new conductor in 40 years time without failing, which should be taken into consideration for estimating remaining life.

TEST C3 - BREAKING LOAD TEST

Objective

The objective of this test is to determine the remaining breaking strength of the aged whole conductor and to compare this value to the rated tensile strength.

Test Results

The result of the breaking load data for the conductor is shown in the following table.

Circuit	Remaining Breaking Strength	Percent of Rated Breaking Strength
Q12S	9,528 kgf (21,006 lbf)	93.4%

The breaking strength of the aged conductor sample is 89.6% of the rated breaking strength of a 605 kcmil conductor (10,206 kgf, 22,500 lbf). The conductor broke on the active side (AV Test) of suspension clamp next to the mouth of armor rods.

Criteria

Hydro One Networks has defined end of life when the remaining tensile strength of the conductor falls below 85% of the RTS. The exception to this is that if the remaining strength is below 85% then:

i) no other tests performed on the conductor can show unsatisfactory results, and
ii) the maximum tension the conductor is subjected to in the field is less than 15% RTS.

Conclusion

Although the remaining tensile strength of the conductor is greater than 85% RTS, the marked reduction from the rated tensile strength is noteworthy for estimating remaining life.

TEST S1 - VISUAL EXAMINATION (Steel and Aluminum Wires)

Objective

The objective of this examination is to make a visual record of the surface condition of the conductor. This can be a very helpful indicator of the general condition of the conductor.

Test Procedure

The conductor was assessed using two (2) methods.

Method 1 - The first method involved examining the same section of conductor that was used for the Tensile, Torsional Ductility, and Remaining Zinc Tests (see Tests S2, S3, and S4).
The test sample used was taken from about 40 m out from the suspension clamp. This section of conductor was considered to be a typical worst-case condition.

Method 2 - The second method involved dissecting the conductor along a 120 m length, from the suspension out to its longest end. The aluminum wire layers were removed and the observations were centered around the condition of the steel layer and core wires. The steel wires were ranked according to their surface condition.

Test Results

The following table summarizes the results from the Method 1 dissection method.

Method 1

Method 1 Dissection Results

Conductor Sample	Component	Observation
Q12S, 100 m from suspension	Outer Layer Aluminum Wires	Outside Surface : see Figure 1a Moderate contamination between strands, heavier on one side, black colored. No signs of burns, flash-over, or lightning. Inside Surface : see Figure 1b White contamination, moderate-heavy pitting, and fretting marks.
	2nd (Middle) Layer Aluminum Wires	Outside Surface : see Figure 2a Moderate contamination, moderate pitting, fretting marks, and white/grey coloured areas. Inside Surface : see Figure 2b Moderate black contamination, some heavy pitting, fretting marks and some white deposits.
	3rd (Inner) Layer Aluminum Wires	Outside Surface : see Figure 3a Heavy contamination, light pitting, fretting marks, covered with white corrosion products. Inside Surface : see Figure 3b Heavy contamination, some light pitting, fretting marks and white deposits, and rust from the steel wires.
Q12S, 100 m from suspension	Steel Layer Wires	Outside Surface : see Figure 4a Moderate to heavy rust marks, heavy pitting, and white contamination. Inside surface : see Figure 4b In some areas rust marks, white contamination, Zn is still intact in other areas.
	Steel Core wire	Light contamination, minor corrosion activity, Zn in still intact.

Method 2

See Appendix D for the results from Method 2 dissection and visual examination.

Criteria

Visual observations of high contamination, corrosion, cracked or broken wires show that the surface of the conductor has deteriorated.

Conclusion

The observations indicate that most layers of the conductor are in advanced stage of deterioration. The conclusion of the visual examination is based on the worst condition found in the sample provided.

Figure 1a   Outer Layer Aluminum Wires - Outside Surface
Circuit Q12S

Figure 1b   Outer Layer Aluminum Wires - Inner Surface
Circuit Q12S

Figure 2a 2nd (Middle) Layer Aluminum Wires - Outside Surface Circuit Q12S

Figure 2b 2nd (Middle) Layer Aluminum Wires - Inside Surface Circuit Q12S

Figure 3a   3rd (Inner) Layer Aluminum Wires - Outside Surface
Circuit Q12S

Figure 3b   3rd (Inner) Layer Aluminum Wires - Inside Surface
Circuit Q12S

Figure 4a   Steel Layer Wires - Outside Surface
Circuit Q12S

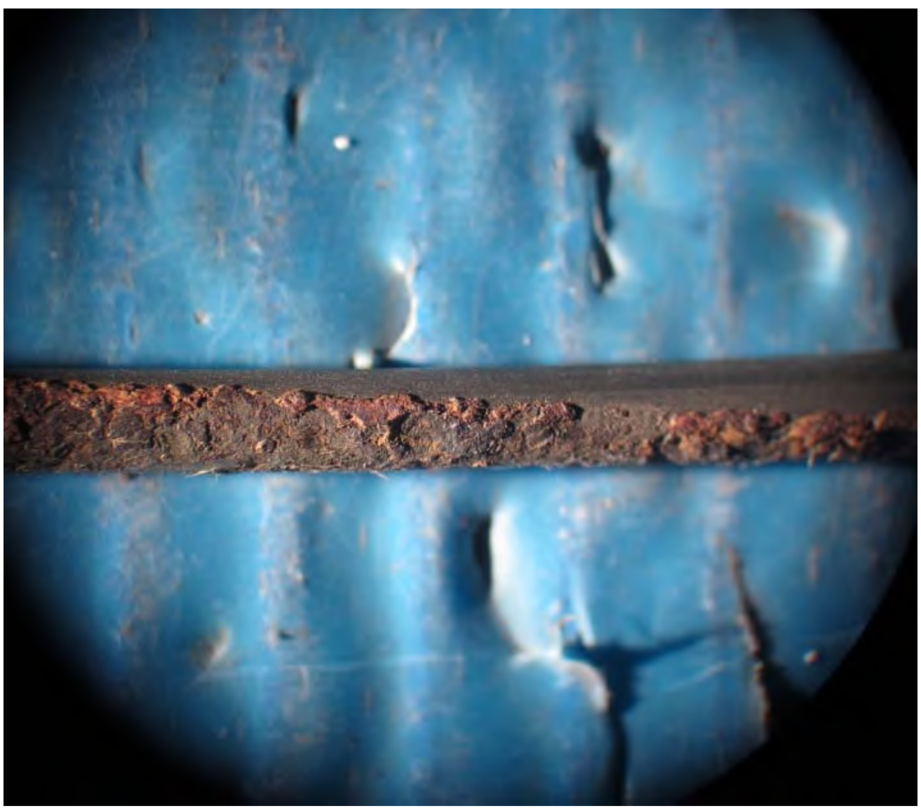


Figure 4b   Steel layer Wires - Magnified View of Area with Severe Corrosion
Circuit Q12S

TEST S2 - TENSILE TEST (Steel and Aluminum Wires)

Objective

The objective of this test is to determine the remaining breaking strength of the aged conductor wires and to compare its value to the rated tensile strength of a new conductor.

Test Set-up

Eighteen (18) of the fifty-four (54) aluminum wires and all seven (7) steel wires were prepared from each conductor. Each sample was about 40 cm in total length. Each sample was put in the test machine so that there was greater than 30 cm distance between the grips.

The test sample used was taken from about 100 m out from the suspension clamp. This section of conductor was considered to be a typical worst-case condition.

Test Procedure

The steel wire samples were preloaded to a value that was equal to an elongation of the sample of 0.10%. An extensionmeter was attached to the sample at the pre-load value to measure the elongation over a 250 mm gauge length. The extensionmeter was offset by 0.10% and the sample was loaded until 1.0% elongation was achieved. The load for 1.0% elongation was noted and the extensionmeter was removed. The load was increased again until failure.

Test Results

The details of the results of the Tensile Test on the individual wires are contained in Appendix C.

The rated breaking strength of a new 605 kcmil conductor is 22,500 lbf.

The calculated breaking strength of the conductor based on the tests on individual wires is listed in the table below.

Conductor Sample	Calculated Remaining Breaking Strength	Percent of Rated Breaking Strength
Q12S	18,755 lbf	83.4%

Criteria

Hydro One Networks has defined end of life when the remaining tensile strength of the conductor falls below 85% of the RTS, with special exception that no other tests confirm (similar results), and the maximum tension in the line is less than 15% RTS.

Conclusion

The remaining tensile strength of the sample based on the tensile test on the individual wires is below 85% RTS. The low value of remaining breaking strength is noteworthy for estimating remaining life.

TEST S3 – TORSIONAL DUCTILITY TEST (Aluminum and Steel Wires)

Objective

The objective of this test is to determine the number of torsional turns to failure for the steel wires. The complex stress-strain conditions that occur in the sample during the torsion test are sensitive to minor variations in surface condition and materials. This test is useful in assessing wire ductility under in-service loading.

Test Set-up

The length of sample is equal to 120 times the wire diameter plus the length required for clamping into the test machine. The sample is tensioned to 1% of the rated breaking strength of the wire.

The test sample used was taken from about 100 m out from the suspension clamp. This section of conductor was considered to be a typical worst-case condition.

Test Procedure

One clamp of the test machine remains stationary while the other rotates along the axis of the wire. The wire is twisted until it fails.

Test Results

The details of the results of the Torsional Ductility Tests on the individual wires are contained in Appendix C.

Eighteen (18) of the fifty-four (54) aluminum wires and all seven (7) steel wires were torsion tested. The average turns to failure of the steel wires is listed in the table below.

Conductor Sample	Average Turns to Failure of Steel Wires *
Q12S at 100m from suspension	3.2

***** (including core wire)

Criteria

Hydro One Networks has defined end of life of the conductor if the average number of turns to failure of the individual steel wires (excluding the core wire) is below seven (7) turns and there is excessive corrosion.

Conclusion

The average turns to failure for the sample is much lower than seven (7). All steel strands showed much lower count of turns to failure (including the steel core wire). This is noteworthy for estimating remaining life.

SUMMARY AND DISCUSSION OF RESULTS

The following table summarizes the key result obtained from each test.

Test No.	Test Name	Key Result
C1	Aeolian Vibration Endurance Test	No visible signs of (additional) breaks or cracks of any wires.
C2	Sheave Test	No visible signs of (additional) breaks or cracks of any wires.
C3	Breaking Load Test	Percent of RTS = 93.4%
S1	Visual Examination	The steel wires are in early stages of deterioration, with some outer surfaces with high corrosion. All three layers of the aluminum wires are at medium to light level of deterioration.
S2	Tensile Test of Individual Wires	Percent of RBS = 83.4%
S3	Torsional Ductility Test	Average of 3.2 turns to failure, while most steel wires indicate less than 7 turns to failure.

The results from the **Aeolian Vibration Endurance Test** suggest that the remaining physical life will be greater than 40 years. The conductor ‘as received’ had no existing broken wires, indicating that fatigue damage has not occurred. This suggests that the remaining physical life of the conductor is in line with the test results.

The results from the **Sheave Test** suggest that the remaining physical life will be greater than 40 years. The conductor ‘as received’ had no existing broken wires (which could cause problems during re-stringing) and this fact should be taken into consideration for estimating remaining life. The test results support estimates of the remaining physical life of the conductor.

Without quantification, the results from the **Visual Examination** also suggest that the remaining physical life of the conductor is reduced.

The results of the **Torsional Ductility Test** indicates that the average number of turns to failure of the steel wires (including the core wire) has been reduced (3.2), while the steel wires are exhibiting much lower turns count (including the core wire). The analysis indicates the remaining physical life will be less than three (3) years.

The results from the **Breaking Load Test on the Whole Conductor** and confirmed by the **Tensile Tests on Individual Wires** suggest that the tensile strength of the conductors will remain above the minimum requirement of 85% RTS for less than three (3) years. Considering the conductor appearance and visible corrosion and deterioration, in the last 80 years the conductors have lost 6.6% (whole conductor) or 16.6% (average individual wire test results) of tensile strength is compared to the RTS of a new conductor. A reassessment of this conductor is important to form a trend to determine the current rate at which tensile strength is being lost.

CONCLUSION

Based on Kinectrics' overall interpretation of all the laboratory tests and assessments on the single conductor sample obtained from Circuit Q12S, it is estimated that the conductor can remain safely in-service for less than three (3) years from the date of testing without failure due to design wind and ice or vibration fatigue loads.

RECOMMENDATIONS

- It is recommended that a second minimum remaining life assessment on circuit Q12S be performed as soon as possible after 10 years from the time of the assessment of the first sample. If the original conductor is replaced before a second assessment is performed, then the original conductor should be reassessed anyway. This will increase the understanding of the degradation process of ageing conductors and will subsequently lead to improving the accuracy of future assessments.
- It is recommended that an atmospheric study on contamination and effects on conductor be undertaken to update the study performed about in 1990 to determine the range of the rate of deterioration. This would determine whether atmospheric conditions have improved or worsened over the past decade and would be quite useful to estimate the present rate of deterioration of the conductors.
- It is recommended that for future conductor remaining life assessments on different circuits, a strategy be developed to retrieve samples from the field. This should be a joint effort between Kinectrics, Hydro One Networks and line crews.
- It is recommended that a laboratory test program be initiated with the objective to improve the understanding and to characterise the deterioration process of ACSR conductors.

Prepared by:

Dmitry Ladin

D. Ladin
Engineer/Scientist
Transmission and Distribution Technologies Business

Mike Colbert

M. Colbert
Senior Technologist
Transmission and Distribution Technologies Business

Greg Brown

G. Brown
Lead Technologist
Transmission and Distribution Technologies Business

Reviewed by:

A. Rizzetto
Engineer/Scientist
Transmission and Distribution Technologies Business

DL:MC:GB:AR:JC

DISCLAIMER

APPENDIX A

DESCRIPTION OF AEOLIAN VIBRATION TEST

Test Set-up and Apparatus

The set-up for the Aeolian Vibration Test is shown in Figure A-1.

The conductor was contained between two intermediate abutments. The active span cable length was 24 m and the passive span cable length was about 12 m for a total cable length of approximately 36 m between the load pins of the deadend clamps. Fixed end abutments were used to load and maintain tension in the cable. As per IEEE Std. 1138, the conductor was tensioned to 2,552 kgf or 25% of the conductor's RTS (10,206 kgf). This was applied using a cantilever weight arm on one of the end abutments.

The deadend assemblies were installed between the intermediate abutments. The original suspension assembly was supported at a height such that the static sag angle of the cable to horizontal was about 1.7 degrees in the active span and about 2.9 degrees in the passive span.

The free loop antinode amplitude of the cable was measured at the second free loop from the suspension assembly towards the shaker. An electronically controlled shaker was used to excite the cable in the vertical plane. The shaker armature was securely fastened to the cable so that it was perpendicular to the cable in the vertical plane.

Test Procedure

The initial target vibration frequency was 34.3 cps, which is the frequency produced by a 4.5 m/s wind (i.e., frequency = 830 ÷ diameter of the conductor in mm). The actual vibration frequency was the system resonance that was nearest to the target frequency and also provided good system stability.

Normally, the target free loop peak-to-peak antinode amplitude would be 8.07 mm or one third of the conductor diameter.

Based on the actual vibration frequency of the test of 34.3 cps, this amplitude was calculated to be 7.9 mm peak-to-peak. This amplitude was maintained at this level in the second free loop from the suspension assembly towards the shaker. The amplitudes in the passive span and the section between the shaker and the deadend in the active span were maintained at levels no greater than one third of the cable diameter.

The conductor was subjected to 100 million vibration cycles. On completion of the aeolian vibration test, the suspension clamp was removed and the outer aluminum wires were inspected for damage. Before removing the outer wires to inspect the steel wires, the conductor was subjected to a Sheave Test described in the next section.

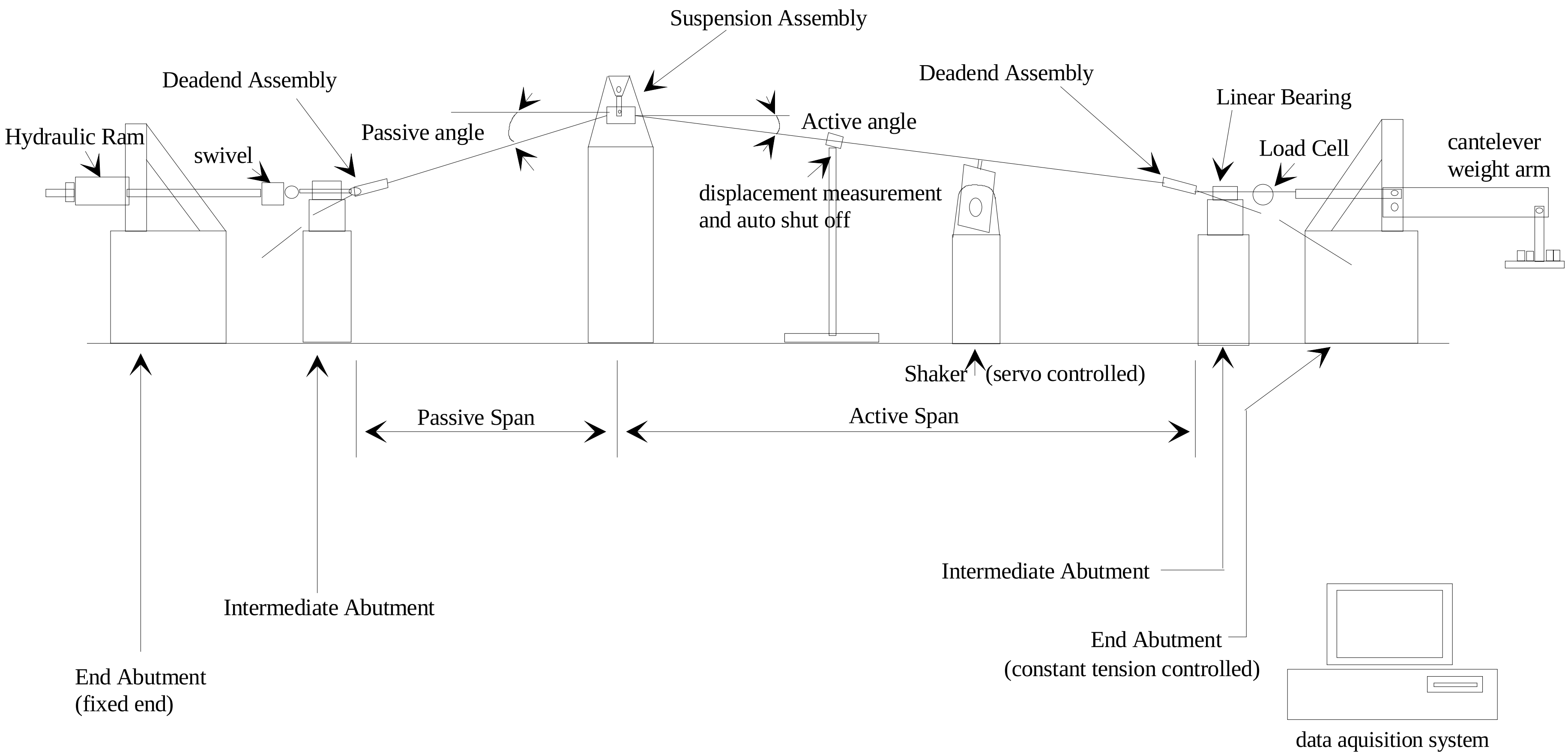


Figure 1 Set-Up for Aeolian Vibration Test

APPENDIX B

DESCRIPTION OF SHEAVE TEST

Test Set-up

The set-up for the Sheave Test is shown in Figure B-1.

Test Apparatus

The length of cable between the deadends load pins was approximately 12 m. The target tension of the cable was 2,041 kgf or 20% of the cable RTS (10,206 kgf). The inside diameter of the sheave was 713 mm. The total angle of the cable over the sheave was 31.2°. The set-up allowed 2.5 m of cable to travel through the sheave at a speed of 0.122 m/sec. A load cell was installed at one end to measure the tension in the cable.

Test Procedure

A two and a half (2.5) meter length of the cable sample was pulled 70 times forward and backward over the sheave (i.e. 35 times each way). The section of cable that passed over the sheave included the area where the suspension clamp was located.

The dissection and visual examination of the cable components within the two and a half (2.5) meter test section were performed after the test.

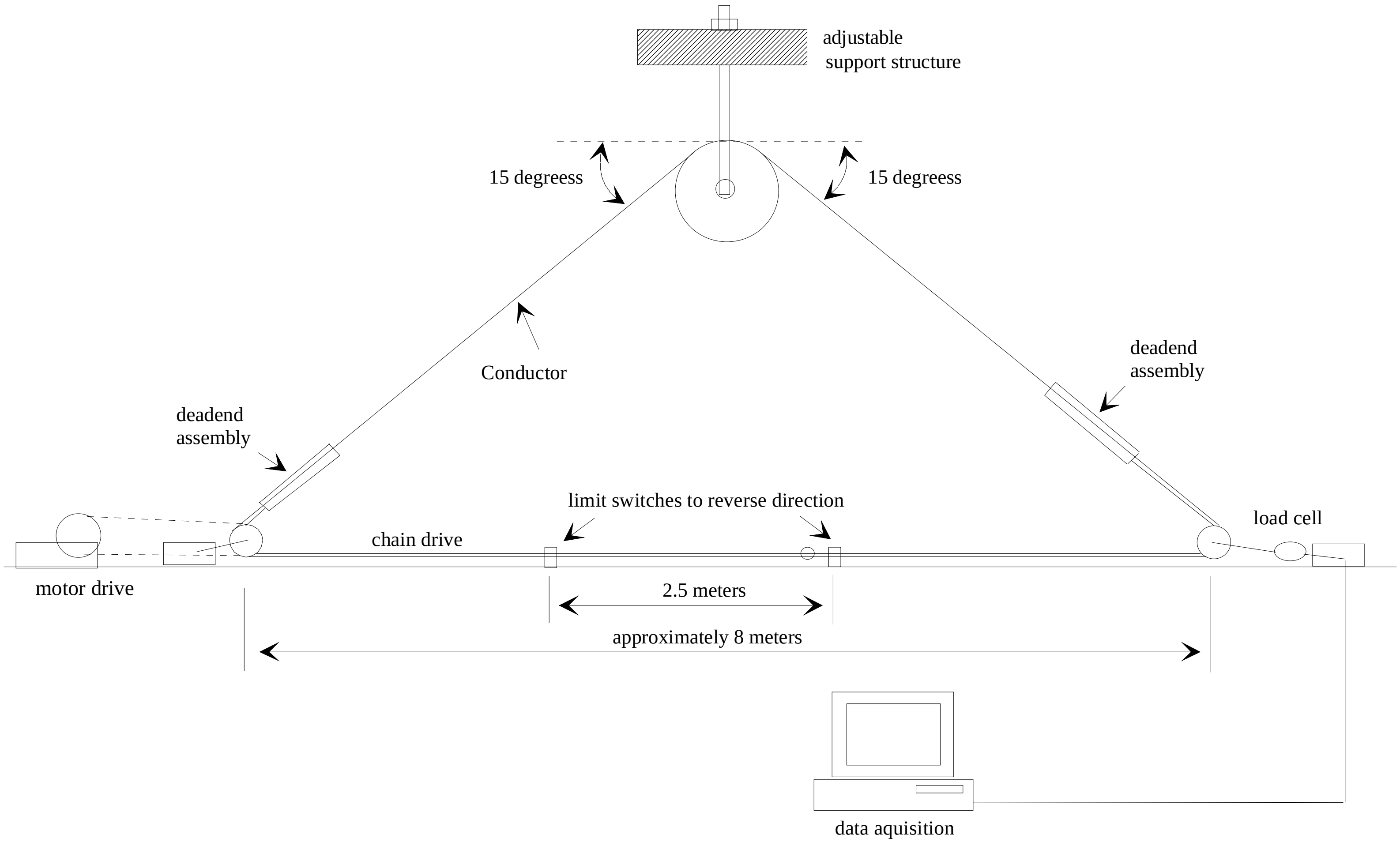


Figure 1   Set-up for Sheave Test

APPENDIX C

TENSION AND TORSION TESTS ON ACSR CONDUCTOR FROM CIRCUIT Q12S

To : Mr. Hassan Hamzeh, Hydro One Networks Inc. Kinectrics Report No.: K-419527-CON-RC-00-R00

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 605.0 kcmil 54/7

TEST DATE : April 28 - May 25, 2014 TESTED by : Mike C KINECTRICS REF. NO. : EOL - 2013 - Q12S

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY or GPS	RECEIVED DATE
Q12S	Warner RD Junction x NOTL MTS#1 Jct, We tested 52.5' to 57' from Suspension.	32 - 33	City of St. Catherines, N 43 09.114', W 079 08.076'	25-Nov-13

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 605.0 kcmil 54/7 Nom. Cable Diameter ** : 0.953 in Measured Cable Diameter : 0.949 in

	Alum. Outer Layer		Alum. Middle Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Min. Breaking Strength	26,000 psi	Min. Breaking Strength	26,000 psi	Min. Breaking Strength	205,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1059 in	for a single wire = 216 lbf	0.1059 in	for a single wire = 216 lbf	0.1059 in	for a single wire = 216 lbf	0.1059 in	Min Breaking Strength of single wire = 1,806 lbf
Area of Wire :	0.0088 sq. in		0.0088 sq. in		0.0088 sq. in		0.0088 sq. in	Min. Load @ 1% Elongation = 1,629 lbf
Number of Wires in Layer :	24		18		12		7	For Tension Test Load @ 1% Elongation **** :
Number of Wires Tested :	6		6		4		7	Preload = 255 lbf., Offset = 0.010 in.
Tension Load for Torsion Test * :	2.16 lbf = 0.979 kgf		2.16 lbf = 0.979 kgf		2.16 lbf = 0.979 kgf		18.06 lbf = 8.190 kgf	
Torsion Test sample length * :	15.21 in = (120 x dia.+ 2.5")		15.21 in = (120 x dia.+ 2.5")		15.21 in = (120 x dia.+ 2.5")		15.21 in = (120 x dia.+ 2.5")	

TEST RESULTS

	Alum. Outer Layer			Alum. Middle Layer			Alum. Inner Layer			Steel and Core Wires				
Measured Wire Diameter : (for identification only)	0.1045 in			0.1050 in			0.1050 in			0.1050 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 alum. wires had :			The outer surface of the steel wires had :				
	Contam	Pitting	Color	Contam	Pitting	Color	Contam	Pitting	Color	Category [1]	Rating [2]	Rust	Pitting	
	moderate	medium	grey	heavy	heavy	white	heavy	heavy	white	5	5	heavy	heavy	See Note A
Comments:	The outer surface had more black contam between wires, on one side than other. Pitting maybe not as severe on lighter side. The inner surface had heavy pitting/corrosion. Lots of white corrosion			The outer surface had lots of white corrosion products. The opposite side was mostly dark contam. The inner surface had lots of white corr products. Had medium to heavy pitting.			The outer surface was covered in white corrosion products. The inner surface had lots of white corrosion products and brown contam from rusted steel wires.			The outer surface hd moderate to heavy corrosion and pitting. Had lots of white corrosion products. The inner surface had no corrosion. Zinc was intact, but maybe thinning. The core wire had no corrosion. Zinc was intact, but maybe thinning.				

WIRE No.	Outer: Number of Turns	Outer: Breaking Strength lbf	Outer: Breaking Strength psi (calc)	Middle: Number of Turns	Middle: Breaking Strength lbf	Middle: 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	19.7	160	18,165	25.4	200	22,706	1.3	169	19,187	2.9	1479	1713	194,480
2	29.7	188	21,344	15.0	187	21,230	1.4	147	16,689	2.4	1386	1617	183,581
3	29.8	185	21,003	2.1	183	20,776	3.0	163	18,506	2.2	1410	1645	186,760
4	36.5	194	22,025	11.0	201	22,820	1.1	181	20,549	5.9	1449	1693	192,210
5	30.5	207	23,501	3.1	181	20,549	0.8	147	16,689	2.6	1462	1701	193,118
6	5.5	187	21,230	1.4	154	17,484	4.3	154	17,484	2.9	1422	1629	184,944
7 (core wire)	-	-	-	-	-	-	-	-	-	9.9	1656	1863	211,510
Average (Steel & Core 'No. of Turns' is Avg. 1 to 6)	25.3	187	21,212	9.7	184	20,928	1.7	165	18,733	3.2	1,466	1,694	192,372

	Alum. Outer Layer	Alum. Middle Layer	Alum. Inner Layer	Steel and Core Wires
Avg. Strength x # of Wires in Layer :	(A) 4,484 lbf	(B) 3,318 lbf	(C) 1,980 lbf	
Total Strength of (Aluminum/Steel) :	A+B+C=(D) 9,782 lbf			(E) 11,861 lbf
Calculated Total Strength of Layer :	(F) 5,496 lbf	(G) 4,122 lbf	(H) 2,748 lbf	(J) 12,640 lbf
Measured / Calculated (%) :	A/F = 81.6%	B/G = 80.5%	C/H = 72.0%	E/J = 93.8%
Total Load on Steel @ 1% Elongation :				(K) 10,264 lbf = 90.0% of Nom 1% Load

Total Measured Breaking Strength :	D+K=(L)	20,046 lbf =	89.1% of Book Value.
Derated Meas. Breaking Strength****	(L) x Derating Factor	18,755 lbf =	83.4% of Book Value.
Rated Breaking Strength ** (book value) :	(M)	22,500 lbf	

- Shaded areas indicate data manually entered or calculated. (Data & Photos Stored in :I:\Mechanical T&D\CONDUCTOR & SKYWIRE ROUTINE TESTING

See Page 2 for Test Methods and Specifications. See Page 2 for asterisk (*) and footnote explanations.

Note A : REMAINING ZINC TEST PERFORMED ON 'CATEGORY 1, RATING 1' STEEL WIRES ONLY. Note : Please see 'Private Information' on Page 3. Revision 2013-14

To : Mr. Hassan Hamzeh, Hydro One Networks Inc.

Kinectrics Report No.: K-419527-CON-RC-00-R00

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 605.0 kcmil 54/7

TEST DATE : April 28 - May 25, 2014 | TESTED by : Mike C | KINECTRICS REF. NO. : EOL - 2013 - Q12S

KINECTRICS

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY	RECEIVED DATE
Q12S	Warner RD Junction x NOTL MTS#1 Jct, We tested 52.5' to 57' from Suspension.	32 - 33	City of St. Catherines, N 43 09.114', W 079 08.076'	25-Nov-13

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 605.0 kcmil 54/7 Nom. Cable Diameter ** : 0.953 in

	Alum. Outer Layer		Alum. Middle Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	26,000 psi	Min. Breaking Strength	26,000 psi	Min. Breaking Strength	26,000 psi	Min. Breaking Strength	205,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1059 in	for a single wire = 216 lbf	0.1059 in	for a single wire = 216 lbf	0.1059 in	for a single wire = 216 lbf	0.1059 in	Min Breaking Strength of single wire = 1,806 lbf
Area of Wire :	0.0088 sq. in		0.0088 sq. in		0.0088 sq. in		0.0088 sq. in	Min. Load @ 1% Elongation = 1,629 lbf
Number of Wires in Layer :	24		18		12		7	For Tension Test Load @ 1% Elongation **** :
Number of Wires Tested :	6		6		4		7	Preload = 255 lbf., Offset = 0.010 in.
Minimum Elongation in 10", at Failure, in Percent (%) : * **	1.5 %		1.5 %		1.5 %		3.5 %	

TEST RESULTS

WIRE No.	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %
1	0.51	0.89	0.67	3.08
2	1.19	0.89	0.39	3.26
3	0.90	0.88	0.43	3.58
4	0.12	0.83	0.79	3.66
5	0.77	0.81	0.44	3.15
6	0.91	0.41	0.42	2.50
7 (core wire)	-	-	-	6.81
Average :	**0.73**	**0.79**	**0.57**	**3.21** (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, Hydro One Category.
[2] 'Rating' from Table 3, Page 3.
[3] 'Remaining Zinc' from Table 1 (H), Page 3.

Revision 2013-14

KINECTRICS REF. NO. : EOL - 2013 - Q12S

ACSR 605.0 kcmil 54/7, CCT : Q12S, Line Section : Warner RD Junction x NOTL MTS#1 Jct. Structure No.: 32 - 33

TABLE 1

Remaining Zinc on Steel and Core Wires

Wire No.	Measured Data: Wgt. of Wire Before Stripping (g) (A)	Measured Data: Ave. Dia. Before Stripping (mm) (B)	Measured Data: Wgt. of Wire After Stripping (g) (C)	Measured Data: Ave. Dia. After Stripping (mm) (D)	Calculated Data: Zinc Thickness (before - after) (mm) (B - D)	Calculated Data: Zinc Thickness (Calculated by Weight) (mm) (E)	Calculated Data: Zinc Removed (before - after) (g) (A - C)	Calculated Data: Zinc Weight [mass] of coating (g/m²) (F)	Calculated Data: Percent Zinc vs. Core Wire % (F/G)
REMAINING ZINC TEST PERFORMED ON "CATEGORY 1, RATING 1" STEEL WIRES ONLY.									

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/m³ 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

Hydro One Category	Kinectrics Category	Percent of Rust by Area
1	Stage 1	none (0 %)
2	Stage 2 a	>0 - 33 %
3	Stage 2 b	33 - 66 %
4	Stage 2 c	66 - <100 %
5	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	Medium surface rust with mild pitting
4	Heavy surface rust with mild to medium pitting
5	Heavy surface rust with medium 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: Craig Pon

C. Pon
Principal Engineer
Transmission & Distribution Technologies

APPENDIX D

RESULTS OF VISUAL EXAMINATION – TEST NO. S1, METHOD 2. DISSECTION ALONG ITS ENTIRE LENGTH ON ACSR CONDUCTOR FROM CIRCUIT Q12S

Test – Layer # 1		Record Length Tested (e.g. "Distance from Suspension" 12.5 to 25)
Aeolian Vibration	Passive	12m
	Active	24m
Sheave		
Breaking		
Wire Tests		

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum					Severity of Wear Aluminum					Comments / Number of Broken Wires
	Outer Surface Rating					Outer Surface Rating					
meters	1	2	3	4	5	1	2	3	4	5	
40.0											
37.5											
35.0											
32.5											
30.0											
27.5											
25.0											
22.5											
20.0											
17.5											
15.0											
12.5											
10.0											
7.5				X				X			
5.0				X				X			
2.5				X				X			
0				X				X			**Suspension Clamp location**
2.5				X				X			
5.0				X				X			
7.5				X				X			
10.0				X				X			
12.5				X				X			
15.0				X				X			
17.5				X				X			
20.0				X				X			

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Layer # 1

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum — Outer Surface Rating					Severity of Wear Aluminum — Outer Surface Rating					Comments / Number of Broken Wires
meters	1	2	3	4	5	1	2	3	4	5	
22.5				X				X			
25.0				X				X			
27.5				X				X			
30.0			X					X			
32.5			X					X			
35.0			X					X			
37.5											Extracted for routine tests
40.0											
42.5											
45.0											
47.5			X					X			
50.0			X					X			
52.5			X					X			
55.0			X					X			
57.5			X					X			
60.0			X					X			
62.5			X					X			
65.0			X					X			
67.5			X					X			
70.0			X					X			
72.5			X					X			
75.0			X					X			
77.5			X					X			
80.0			X					X			
82.5			X					X			
85.0			X					X			
87.5			X					X			
90.0			X					X			
92.5			X					X			
95.0			X					X			

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Layer # 1

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum — Outer Surface Rating					Severity of Wear Aluminum — Outer Surface Rating					Comments / Number of Broken Wires
meters	1	2	3	4	5	1	2	3	4	5	
97.5			X					X			
100.0			X					X			
102.5			X					X			
105.0			X					X			
107.5			X					X			
110.0			X					X			
112.5			X					X			
115.0			X					X			
117.5			X					X			
120.0			X					X			
122.5			X					X			
125.0			X					X			
127.5			X					X			
130.0			X					X			
132.5			X					X			
135.0			X					X			
137.5			X					X			
140.0			X					X			
142.5			X					X			Significant accumulation of corrosion products (white) between strands
145.0			X					X			
147.5			X					X			
150.0			X					X			
152.5			X					X			
155.0			X					X			
157.5			X					X			
160.0			X					X			
162.5			X					X			
165.0			X					X			
167.5			X					X			
170.0			X					X			
172.5			X					X			

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Test – Layer # 2		Record Length Tested (e.g. “Distance from Suspension” 12.5 to 25)
Aeolian Vibration	Passive	
	Active	
Sheave		
Breaking		
Wire Tests		

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum — Outer Surface Rating					Severity of Wear Aluminum — Outer Surface Rating					Comments / Number of Broken Wires
meters	**1**	**2**	**3**	**4**	**5**	**1**	**2**	**3**	**4**	**5**	
40.0											
37.5											
35.0											
32.5											
30.0											
27.5											
25.0											
22.5											
20.0											
17.5											
15.0											
12.5											
10.0											
7.5			X					X			
5.0			X					X			
2.5			X				X				
0			X				X				**Suspension Clamp location**
2.5			X				X				
5.0			X					X			
7.5			X					X			
10.0			X					X			
12.5			X					X			
15.0			X					X			
17.5			X					X			
20.0			X					X			

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Layer # 2

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum					Severity of Wear Aluminum					Comments / Number of Broken Wires
	Outer Surface Rating					Outer Surface Rating					
meters	**1**	**2**	**3**	**4**	**5**	**1**	**2**	**3**	**4**	**5**	
22.5			X					X			
25.0			X					X			
27.5			X					X			
30.0			X					X			
32.5			X					X			
35.0				X				X			
37.5											Extracted for routine tests
40.0											
42.5											
45.0											
47.5			X					X			
50.0				X				X			
52.5				X				X			
55.0				X				X			
57.5				X				X			
60.0				X				X			
62.5				X				X			
65.0				X				X			
67.5				X				X			
70.0				X			X				
72.5				X			X				
75.0				X			X				
77.5				X			X				
80.0				X			X				
82.5				X			X				
85.0				X				X			Presense of white residue
87.5			X					X			
90.0				X				X			
92.5				X				X			
95.0				X				X			

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Layer # 2

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum — Outer Surface Rating					Severity of Wear Aluminum — Outer Surface Rating					Comments / Number of Broken Wires
meters	1	2	3	4	5	1	2	3	4	5	
97.5				X				X			Presense of white residue
100.0				X				X			
102.5				X				X			
105.0				X				X			
107.5				X				X			
110.0				X				X			
112.5				X				X			
115.0				X				X			Three (3) broken strands
117.5				X				X			
120.0				X				X			
122.5				X				X			
125.0				X				X			
127.5				X				X			
130.0				X				X			
132.5				X				X			
135.0				X				X			
137.5				X				X			
140.0				X				X			Lots of accumulated white and black corrosion products. Some small clean metal spots in certain areas.
142.5				X				X			
145.0				X				X			
147.5				X				X			
150.0				X				X			
152.5				X				X			
155.0				X				X			
157.5				X				X			
160.0				X				X			
162.5				X				X			
165.0				X				X			
167.5				X				X			
170.0				X				X			
172.5				X				X			

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Test – Layer # 3		Record Length Tested (e.g. "Distance from Suspension" 12.5 to 25)
Aeolian Vibration	Passive	
	Active	
Sheave		
Breaking		
Wire Tests		

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum					Severity of Wear Aluminum					Comments / Number of Broken Wires
	Outer Surface Rating					Outer Surface Rating					
meters	**1**	**2**	**3**	**4**	**5**	**1**	**2**	**3**	**4**	**5**	
40.0											
37.5											
35.0											
32.5											
30.0											
27.5											
25.0											
22.5											
20.0											
17.5											
15.0											
12.5											
10.0											
7.5			X				X				
5.0			X				X				
2.5			X				X				
0		X					X				**Suspension Clamp location**
2.5			X				X				
5.0			X				X				
7.5		X					X				
10.0			X				X				
12.5		X					X				
15.0		X						X			
17.5		X					X				
20.0			X					X			

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration;	5	Dark: severe signs of wear (fret marks resulting in

	dark scale build-up		significant metal loss and/or broken wires; pitting)

Layer # 3

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum Outer Surface Rating					Severity of Wear Aluminum Outer Surface Rating					Comments / Number of Broken Wires
meters	**1**	**2**	**3**	**4**	**5**	**1**	**2**	**3**	**4**	**5**	
22.5			X					X			
25.0			X					X			
27.5			X					X			
30.0			X					X			
32.5			X					X			
35.0			X					X			
37.5											Extracted for routine tests
40.0											
42.5											
45.0											
47.5				X				X			
50.0				X				X			
52.5				X				X			
55.0				X				X			
57.5				X				X			
60.0				X				X			
62.5				X				X			
65.0				X				X			
67.5				X				X			
70.0				X				X			
72.5				X				X			
75.0				X				X			
77.5				X				X			
80.0				X				X			
82.5				X				X			
85.0				X				X			
87.5				X				X			
90.0				X				X			Presence of white residue
92.5				X				X			
95.0				X				X			

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Layer # 3

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum — Outer Surface Rating					Severity of Wear Aluminum — Outer Surface Rating					Comments / Number of Broken Wires
meters	1	2	3	4	5	1	2	3	4	5	
97.5				X				X			
100.0				X				X			
102.5				X				X			
105.0				X			X				
107.5				X				X			
110.0				X				X			
112.5				X			X				
115.0				X				X			
117.5				X				X			
120.0			X					X			
122.5			X				X				
125.0			X				X				
127.5			X				X				
130.0			X					X			
132.5			X				X				
135.0			X				X				
137.5			X				X				
140.0			X				X				White/black powder residue
142.5				X				X			
145.0				X				X			
147.5			X				X				
150.0			X				X				
152.5				X				X			Small patches of white/black powder residue
155.0			X				X				
157.5			X				X				
160.0			X				X				
162.5			X				X				
165.0			X				X				
167.5			X				X				
170.0			X				X				
172.5			X				X				

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Distance from Suspension	Extent of Rust (Steel)					Severity of Rust (Steel)					Extent of Rust (Steel Core)	Severity of Rust (Steel Core)	Comments
	Stage					Rating					Stage	Rating	
meters	1	2a	2b	2c	3	1	2	3	4	5			
40.0													
37.5													
35.0													
32.5													
30.0													
27.5													
25.0													
22.5													
20.0													
17.5													
15.0													
12.5													
10.0													
7.5		X					X						
5.0		X					X						
2.5		X					X						
0		X					X						Suspension Clamp location
2.5		X					X						
5.0		X					X						
7.5		X					X						
10.0		X					X						
12.5		X					X						
15.0		X					X						
17.5		X						X					
20.0			X					X					
22.5			X					X					
25.0			X				X						
27.5			X				X						
30.0			X				X						

Category	% Rust by Area on Outer Surface of Steel Wires	Rating	Severity of Rust on Outer Surface of Steel Wires
Stage 1	none (0 %)	1	No Rust, 100% galvanized
Stage 2 a	>0 - 33 %	2	Light surface rust and negligible pitting
Stage 2 b	33 - 66 %	3	Medium surface rust with mild pitting
Stage 2 c	66 - <100 %	4	Heavy surface rust with mild to medium pitting
Stage 3	100%	5	Heavy surface rust with medium to heavy pitting

Distance from Suspension	Extent of Rust (Steel)					Severity of Rust (Steel)					Extent of Rust (Steel Core)	Severity of Rust (Steel Core)	Comments
	Stage					Rating					Stage	Rating	
meters	1	2a	2b	2c	3	1	2	3	4	5			
30.0			X				X						
32.5			X					X					
35.0			X					X					
37.5			X					X					
40.0													Extracted for routine tests
42.5													
45.0													
47.5													
50.0			X					X					3” section of corr.
52.5			X					X					
55.0			X					X					
57.5			X					X					3” section of corr.
60.0			X					X					
62.5			X					X					
65.0			X					X					
67.5			X					X					
70.0			X					X					
72.5			X					X					
75.0			X						X				
77.5			X					X					
80.0			X					X					
82.5			X					X					
85.0			X						X				
87.5			X					X					
90.0			X					X					
92.5			X					X					
95.0			X					X					
97.5		X					X						
100.0		X					X						
102.5		X					X						
105.0		X					X						
107.5		X					X						
110.0		X					X						

Category	% Rust by Area on Outer Surface of Steel Wires	Rating	Severity of Rust on Outer Surface of Steel Wires
Stage 1	none (0 %)	1	No Rust, 100% galvanized
Stage 2 a	>0 - 33 %	2	Light surface rust and negligible pitting
Stage 2 b	33 - 66 %	3	Medium surface rust with mild pitting
Stage 2 c	66 - <100 %	4	Heavy surface rust with mild to medium pitting
Stage 3	100%	5	Heavy surface rust with medium to heavy pitting

Distance from Suspension	Extent of Rust (Steel)					Severity of Rust (Steel)					Extent of Rust (Steel Core)	Severity of Rust (Steel Core)	Comments
	Stage					Rating					Stage	Rating	
meters	1	2a	2b	2c	3	1	2	3	4	5			
112.5			X				X						
115.0			X				X						
117.5				X				X					
120.0				X					X				
122.5				X					X				
125.0			X					X					
127.5			X					X					
130.0			X					X					
132.5			X					X					
135.0		X						X					
137.5		X						X					
140.0		X					X						
142.5		X					X						
145.0		X					X						
147.5		X					X						
150.0		X					X						
152.5		X					X						
155.0		X					X						
157.5		X						X					
160.0		X						X					
162.5		X							X				
165.0		X						X					
167.5		X							X				
170.0		X					X						
172.5		X						X					

Category	% Rust by Area on Outer Surface of Steel Wires	Rating	Severity of Rust on Outer Surface of Steel Wires
Stage 1	none (0 %)	1	No Rust, 100% galvanized
Stage 2 a	>0 - 33 %	2	Light surface rust and negligible pitting
Stage 2 b	33 - 66 %	3	Medium surface rust with mild pitting
Stage 2 c	66 - <100 %	4	Heavy surface rust with mild to medium pitting
Stage 3	100%	5	Heavy surface rust with medium to heavy pitting

DISTRIBUTION

Mr. Hassan Hamzeh (3)	Sustainment Investment Planning Hydro One Networks Inc. 483 Bay Street, North Tower, 15th Floor Toronto, Ontario M5G 2P5
Dmitry Ladin (1)	Kinectrics Inc., Unit 2 800 Kipling Ave, KB 223 Toronto, Ontario M8Z 5G5 Canada

Transmission Line Refurbishment on H24C

Summary Recommendation:

We are requesting approval for \$35.6M to address the deteriorated condition and end-of-life assets as determined by condition assessment activities related to a 54.4km section of the 230 kV transmission line circuit (H24C), between Marine Junction and Oshawa North Junction. The investment will reduce safety risk and improve the supply reliability to industrial, commercial and residential customers in the cities of Oshawa and Whitby, including General Motors - Oshawa, Atlantic Packaging, and Gerdau Steel.

Investment Details:

In-service: December, 2016

The H24C line, from Marine Junction to Oshawa North Junction, is a 230kV single circuit transmission line that was built in 1929. This circuit is critical for the supply to industrial, commercial and residential customers in the cities of Oshawa and Whitby, including General Motors - Oshawa, Atlantic Packaging, and Gerdau Steel.

This investment funds the reinforcement of 168 steel towers and replacement of conductors, shield wires, insulators and all associated hardware. This will include the complete replacement of 14 steel structures due to major structural damage, 27 tower extensions to correct substandard clearances, and the addition of 16 km of access roads and 48 working pads to enable safe construction and restoration of the required transmission line facilities.

Refurbishing is recommended as it is the most cost effective alternative for mitigating performance degradation. Over the last 5 years (2010-2014), there have been 2 sustained and 2 momentary line outages on the circuit. This investment will reduce the safety risk while improving reliability of supply, public safety and customer satisfaction.

Benefits:

The investment will provide the following benefits:

(a) Reduce the risk of customer interruptions and improve reliability
(b) Reduce safety risks by reducing the possibility of transmission line component failures
(c) Meet current Hydro One and CSA design standards
(d) Prolong the line's service life for another 50 years

Estimated Costs & In-service:

The cost breakdown is as follows:

Category	Cost ($M)
Material	8.3
Construction	18.2
Project Management, Engineering & Commissioning	1.3
Contingency	2.7
Interest & Overhead	5.1
Total	35.6

Previous approved expenditures of $5.7 for materials and detailed engineering is included in the total estimate. The unit cost of this project is higher than similar projects mainly because of the number of towers to be replaced and modified by adding extensions (to increase their height) due to severe damage and sub-standard clearance.

The estimate is based upon a visual inspection of subset of towers and completion of all detailed engineering. The contingency on construction, material, and engineering is mainly to cover any deviation from the original design during execution as per actual tower condition. This investment is included in the approved 2016 Budget and will be included in May 2016 Transmission rate filing.

Other Alternatives Considered

Status Quo or Do nothing Alternative
Continue to operate H24C in current condition and maintain the aging transmission line on as required basis (i.e. repair as it fails). This alternative was rejected because it would result in an increased risk of overhead line component failures and compromise public safety and reliability of supply to customers in the area.

Alternative One: Rebuild the Overhead Transmission Line, H24C, Marine Junction X Oshawa North Junction
This would be a complete rebuild of the existing 230 kV transmission line (54.5 km) on the existing right of way. This alternative was rejected because (i) the cost of this option is more than two times higher than refurbishment while not affording any incremental material benefit in reliability, public safety, customer satisfaction or regulatory/legal compliance; and (ii) new environmental and regulatory approvals would be required which would further increase resource commitments and project timelines.

Regulatory Considerations

$21.7M of funding for this project was included in 2014 as part of the OEB approved 2015/16 TX Rate Filing (EB-2014-0140). The estimate provided in the last rate case did not include the replacement of towers as these requirements were not identified until detailed engineering was complete. The difference is therefore primarily scope differences. We will include the updated amount in the upcoming Transmission rate filing.

This Lines refurbishment project involves a capital replacement of the lines and associated components and will not trigger a Section 92 application.

Risks and Mitigation

First Nations and Metis Relations

First Nations and Métis Relations Risk Level: Medium – project is located in an area where there are likely recognized First Nations rights. As this project does not trigger environmental assessments, it potentially excludes First Nations from participating in the environmental assessment of effects caused by constructing new access roads. This risk is being mitigated by notifying surrounding First Nations and, as required, addressing concerns.

Outages

Outages Risk Level: Medium – A long outage period is required. The Grid Control Centre might require the circuit to be restored at any time due to unexpected operating conditions. Customer impact of the extended outage will be managed by long term planning and coordination between Hydro One and the customers fed off the circuits. At this time, we consider this risk can be mitigated and have not included contingency for unexpected outages.

This Approval ($): $13.4M	Previous Approval ($): $22.2M	Current est. of Total Cost ($): $35.6M
Signature Block:		
Submitted by: Chong Kiat NG	Title: Director, Transmission Asset Planning	Date: April 7, 2016
Approved by: Karen Newman	Title: VP, Corporate Controller	Date: April 8/16
Approved by: Mike Penstone	Title: VP Planning	Date: April 7 2016
Approved by: Michael Vels	Title: Chief Financial Officer	Date: April 8/16
Approved by: Mayo Schmidt	Title: President & CEO	Date: April 12, 2016

Appendix: Required information for SAP data input

Yearly Expenditures

	2012-2015($M)	2016($M)	2017($M)	Total ($M)
Capital* and MFA	5.0	23.5	2.8	31.3
OM&A and Removals	0.7	3.2	0.4	4.3
Gross Investment Cost*	5.7	26.7	3.2	35.6
Recoverable	0.0	0.0	0.0	0.0
Net Investment Cost	5.7	26.7	3.2	35.6

* Includes overhead and AFUDC at current rates

	2012-2015($M)	2016($M)	2017($M)	Total ($M)
In-Service $ Additions	0.0	28.5	2.8	31.3

In-service Date:	December, 2016
Business Case Summary #:	51000020
Appropriation Request #:	21986
Subject ID #	80225
Investment Driver:	N.T.C.1.12
Productivity Cards?	No
Director	CK Ng
Planner	Bill Kong

Scientific Research & Experimental Development Tax Credits (SR&ED):

- Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? No

- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? No

To: Hydro One Networks Inc.
483 Bay Street, North Tower, 15th Floor
Toronto, ON
M5G 2P5

ESTIMATE OF REMAINING LIFE OF CONDUCTORS ON CIRCUIT H24C

Kinectrics Report No: K-419095-RC-0001-R00

April 11, 2011

C. Dimnik
Transmission & Distribution Technologies Business

EXECUTIVE SUMMARY

Kinectrics Inc. carried out an analysis and assessment to estimate the minimum remaining life of the original 795 kcmil, 54/7 ACSR conductor on transmission line Circuit H24C between Marine Jct. and Oshawa North Jct. The conductor was originally installed in 1929. One (1) conductor sample was retrieved between Towers 700 and 720 for testing and evaluation. Investment Planning of Hydro One Network Management has assumed this sample is typical of the condition along the line section and therefore the estimate of its' remaining life would be representative for the remainder of the line.

The estimate of minimum remaining life is based on a series of laboratory tests performed on the sample. The conductor had been in-service for about 80 years at the time of testing. Generally, the aluminum wires are light to moderately contaminated with no pitting. The steel wires show light surface rust, with negligible pitting. The remaining tensile strength of the conductor is 91.3% of the rated tensile strength based on a breaking load test of the whole conductor and 93.0% based on breaking load tests on the individual wires.

Based on Kinectrics' overall interpretation of the laboratory test results, assessments and analyses on the conductor sample obtained from Circuit H24C, the estimated minimum remaining life is **three (3)** years. The conductor should be able to remain safely in-service for this time without failure due to design wind and ice or vibration fatigue loads.

It is noted that the estimate of minimum remaining life is based on only one (1) sample that was assumed to be typical of the condition of the conductor along the entire line section. The confidence level would be higher if there were a greater number of samples tested. In addition, the details of the actual loading and weather conditions on circuit H24C are not fully known.

ESTIMATE OF REMAINING LIFE OF CONDUCTORS ON CIRCUIT H24C

Kinectrics Report No: K-419095-RC-0001-R00

April 11, 2011

C. Dimnik
Transmission & Distribution Technologies Business

INTRODUCTION

Many transmission lines in Ontario are well beyond their original accounting life (60 years) but have not yet reached their physical end of life. With increasing competitive pressures, it is becoming more important to assess the present day condition of aged transmission lines with the end objective to estimate the remaining life. Conductors are considered to be the critical component of transmission lines. This is because conductors identified for replacement initiates a Transmission Line Replacement and Refurbishment (TLR&R) project. This project then drives the assessment and replacement of other major components such as structures, insulators, hardware and grounding. Large capital expenditures can be deferred and life cycle asset management can be optimized if the remaining physical life of conductors can be estimated with reasonable accuracy and confidence.

The main objective of the assessment is to assign a minimum remaining life of the conductor based on its current physical condition. A discussion of remaining life of conductors is in Appendix A.

SAMPLES FOR LABORATORY TESTING

Quantity

The number of samples available for laboratory testing will affect the statistical significance of the results. The remaining life estimate is based on only one (1) sample that was assumed to be typical of the condition of the conductor along the entire line section.

Quality

This assessment determines the condition of an entire line section by examination of a very small sample length of the line. Site-specific conditions such as localized pollution sources are not known therefore cannot be taken into account. However, Hydro One Networks management considers that generally for line sections less than 20 km the average atmospheric contamination and corrosion conditions are assumed to be similar.

The location where the samples are taken within the line section and the location of the samples within the span are significant factors in whether the worst-case location has been selected.

To identify which areas of the province were more vulnerable to corrosion of conductors and other tower steel, a corrosivity map of Ontario was produced in the mid-late 1980's by Ontario Hydro Research Division. Since then, the atmospheric conditions have been influenced by many factors such as urbanization, government and industry regulations, the economy, etc. The map is out of date and should be updated. The estimate of minimum remaining life is based solely on the present condition of the conductor samples. A new atmospheric corrosion study would:

1) help determine the rate of deterioration,
2) help determine where to take other samples,
3) help understand the corrosion process and
4) help determine the source of the contaminants.

TEST SAMPLE FOR H24C

Circuit H24C extends approximately 54 km from Marine Jct. to Oshawa North Jct. This section of the line was constructed in 1929 with 795 kcmil, 54/7 ACSR conductor. The conductor is constructed with 54 aluminum wires stranded in 3 layers over 7 galvanized steel wires. The conductor sample for testing was removed from the span between Towers 700 and 720. The conductor had been in-service for 80 years at the time it was removed. It is assumed that the condition of this sample is typical for this vicinity of the circuit.

The conductor has the following properties:

Size:	795 kcmil conductor
Stranding:	ACSR 54/7 (3 layers of aluminum wires, 2 layers of steel wires)
Wire Diameters:	Aluminium Wires: 0.1213 inches (3.08mm)
	Steel Wires: 0.1213 (3.08mm)
Rated Tensile Strength (RTS)	28,550 lbf (12,950 kgf)
Outer Diameter:	1.092 inches (27.74mm)
Weight:	1.0222 lbf/ft (1.5212kg/m)

The estimate of minimum remaining life is based on a series of laboratory tests performed on the one (1) sample taken from this circuit. The sample was obtained from the field with the suspension clamp still installed on the conductor. The sample was about 50 m in length on one side of the suspension clamp.

TEST OBJECTIVE

The objective of this study is to estimate the minimum remaining physical life of the conductor installed on Circuit H24C.

This is the seventeenth study for Hydro One using a variety of tests to estimate the remaining physical life of aged conductors. It is expected that some tests will contribute more than others. From earlier studies of the other lines, tests have been added, deleted or modified. Tests have been evaluated and chosen based on the type of deterioration and contamination for each situation. It is expected that the accuracy of estimating the remaining physical life should improve by establishing trends over a number of years.

TEST PROGRAM

The following tests were performed.

Conductor Tests

TEST NO.	TEST NAME	COMMENT
C1	Aeolian Vibration Endurance Test	On whole conductor sample
C2	Sheave Test	On whole conductor sample
C3	Breaking Load Test	On whole conductor sample

Individual Wire Tests

TEST NO.	TEST NAME	COMMENT
S1	Visual Examination	On Steel and Aluminum Wires
S2	Tensile Test on Individual Wires	On Steel and Aluminum Wires
S3	Torsional Ductility Test	On Steel and Aluminum Wires

TEST C1 - AEOLIAN VIBRATION ENDURANCE TEST

Objective

The objective of the Aeolian Vibration Endurance Test is to subject the aged conductor to relatively severe aeolian vibrations for an equivalent number of cycles that may be experienced in a 40-50 year design life. The test procedure is based on IEEE Std 1138-1994, *"IEEE Standard Construction of Composite Fiber Optic Overhead Ground Wire (OPGW) for Use on Electric Utility Power Lines"*. The test was originally developed to qualify OPGW against fatigue damage that may result from excessive levels of aeolian vibrations. Since the aluminum wires for OPGW and ACSR conductors are similar, the test is applicable to the conductor installed on Circuit H24C. The aluminium wires are vulnerable to fatigue damage. They will fail at suspension clamps, in-line splices, vibration dampers, spacer-dampers, marker balls, etc. It is very important that field samples include suspension clamps and in-line splices still installed on the conductor.

If it can be shown that the aged conductor can endure these laboratory vibrations after already experiencing many years of unknown field vibration, then the existing conductor in the field would be considered qualified to endure in-service aeolian vibrations for another 40-50 years. This test provides good confidence against fatigue failures.

Test Set-up and Procedure

The description of the set-up and procedure is in Appendix B.

The suspension assembly, as-received, was loose on the conductor. The field suspension assembly was removed, and Kinectrics supplied a suitable suspension assembly to complete the Aeolian Vibration Test.

Test Results

The result of the Aeolian Vibration Test of the tested sample is listed in Table 1.

Table 1 Results of Aeolian Vibration Endurance Test

Test Dates	Test Tension	Cycles	Amplitude	Frequency	Results
January 10 – February 16, 2011	25% RTS = 3,238 kgf (7,139 lbf)	100 million	Between 9.5 mm and 10.2 mm peak-to-peak	~ 31 Hz	No visible signs of breaks or cracks of any the wires.

Criteria

If the aged samples are able to endure 100 million cycles without fatigue damage, then it can be concluded that the existing conductor can remain in-service for over forty (40) years without fatigue failure.

Conclusion

The results from the Aeolian Vibration Endurance Test indicate the existing H24C conductor can remain in-service for more than forty (40) years. This is noteworthy for estimating remaining life.

TEST C2 - SHEAVE TEST

Objective

The objective of the Sheave Test is to determine the ability of the conductor to withstand passing over a sheave a number of times without undesirable damage to the conductor. The test procedure is based on IEEE Std 1138-1994, *"IEEE Standard Construction of Composite Fiber Optic Overhead Ground Wire (OPGW) for Use on Electric Utility Power Lines"*

Conductor replacement involves using the existing, in-service conductor to pull in the new conductor. It is critical that the wires of the existing conductor pass through the sheaves without breaking. Broken wires separate from the body of the conductor and get entwined in the sheaves. In the worst case the conductor can break. At a minimum, the stringing operation will be interrupted and result in costly delays. Increased hazards to workers and the public are also a cause for concern.

Test Set-up and Procedure

The description of the set-up and procedure is in Appendix C.

Test Results

The sample tested had no other visible signs of breaks, cracks or failure of any the wires. The results of the Sheave Test are listed in Table 2.

Table 2 Results of Sheave Test

Test Date	Conductor Tension	Sheave Diameter	Angle over Sheave	Number Of Cycles	Results
March 16, 2011	25% RTS = 3,238 kgf (7,138 lbf)	713 mm (28 inch)	31.4º	35	No wires were broken.

Criteria

If the aged samples are able to endure passing over a sheave 70 times after also experiencing 100 million cycles of simulated aeolian vibration without failure, then it can be concluded that the existing conductor can remain in-service for an equivalent lifetime.

Conclusion

The result of the Sheave Test provides confidence that the existing H24C conductor could pull in a new conductor in 40 years time without failing.

TEST C3 - BREAKING LOAD TEST

Objective

The objective of this test is to determine the remaining breaking strength of the aged conductor and to compare this value to the rated tensile strength.

Test Results

The result of the breaking load data for the conductor is shown in Table 3.

Table 3 Results of Breaking Load Test on Whole Conductor

Conductor Sample	Remaining Breaking Strength	Percent of Rated Breaking Strength
Tower 700 – 720	11,822 kgf (26,063 lbf)	91.3%

Criteria

Hydro One Networks has defined end of life when the remaining tensile strength of the conductor falls below 85% of the RTS. The exception to this is that if the remaining strength is below 85% then:

i) no other tests performed on the conductor can show unsatisfactory results and
ii) the maximum tension the conductor is subjected to in the field is less than 15% RTS

Conclusion

The results of the Breaking Load Test on the whole conductor sample indicates that the H24C conductor is in fair condition.

TEST S1 - VISUAL EXAMINATION (Steel and Aluminum Wires)

Objective

The objective of this examination is to make a visual record of the surface condition of the conductor. This can be a very helpful indicator of the general condition of the conductor.

Test Procedure

The conductor was assessed using two (2) methods.

Method 1 - The first method involved examining the same section of conductor that was used for the Tensile, Torsional Ductility, and Remaining Zinc Tests (see Tests S2, S3, and S4). The test sample used was taken from about 50 m out from the suspension clamp. This section of conductor was considered to be a typical worst-case condition.

Method 2 - The second method involved dissecting the conductor along a 50 m length, from the suspension out to its longest end. The aluminium wires were inspected and observations made about the extent of discoloration, contamination and wear. These observations were recorded for information purposes. The aluminum wires were removed, and the observations were centered around the condition of the steel layer and core wires. The steel wires were ranked according to their surface condition.

Test Results

Method 1

Table 4 summarizes the results from the Method 1 dissection method.

Table 4 Method 1 Dissection Results

<table>
<tr><th>Conductor Sample</th><th>Component</th><th>Layer</th><th>Surface</th><th>Observation</th></tr>
<tr><td rowspan="8">H24C
Tower 700 – 720, at 50 m from suspension</td><td rowspan="6">Aluminium Wires</td><td rowspan="2">Outer (Figures 1a, 1b)</td><td>Outer</td><td>Mild contamination, no pitting</td></tr>
<tr><td>Inner</td><td>Heavy contamination, dark in colour. No pitting</td></tr>
<tr><td rowspan="2">Middle (Figures 2a, 2b)</td><td>Outer</td><td>Heavy contamination, dark in colour. No pitting</td></tr>
<tr><td>Inner</td><td>Mild contamination, dark in colour. Evidence of light fretting, but no pitting.</td></tr>
<tr><td rowspan="2">Inner (Figures 3a, 3b)</td><td>Outer</td><td>Mild contamination, dark in colour. Evidence of light fretting, but no pitting.</td></tr>
<tr><td>Inner</td><td>Mild contamination, dark in colour. Evidence of light fretting, but no pitting.</td></tr>
<tr><td rowspan="2">Steel Core wires</td><td>6 Wires (Figures 4a, 4b)</td><td>Outer/Inner</td><td>No signs of surface rust or pitting, with galvanizing intact.</td></tr>
<tr><td>Steel Core Wire (Figure 4b)</td><td>Outer/Inner</td><td>No signs of surface rust or pitting, with galvanizing intact.</td></tr>
</table>

Method 2

The observations from the dissection and visual examination along the ½ span are contained in Appendix E. The results show that that the aluminum wires had medium-to-dark scale build-up along the complete ½ span dissection. Light-to-medium severity of fretting and wear was recorded near the suspension assembly, with light severity noted throughout the remaining ½ span.

The steel core had almost no signs of rust under the suspension assembly. The remaining length of steel core had areas with no rust (i.e. Stage 1), and areas with some rust, ranging from 0% to 33% of the surface area (i.e. Stage 2a). The severity in areas with some rust was consistent, with light surface rust and negligible pitting (i.e. Rating 2).

After the breaking load test, the ½ span dissection revealed several broken aluminum wires in the middle layer. The broken wires were found from 0 – 2.5 m from the suspension assembly. Refer to Figure 5 for a photograph of one of the locations where broken wires were found in the 2nd aluminum layer, beneath the suspension assembly.

After the breaking load test, the ½ span dissection also revealed an area with localized contamination, refer to Figure 6. The contamination was found 10 – 12.5 m from the suspension assembly.

Criteria

Visual observations of high contamination, corrosion, cracked or broken wires would show that the surface of the conductor has deteriorated.

Conclusion

There is light signs of corrosion activity of the steel core. The amount and extent of rust and contamination show that the conductor is in the early stages of deterioration.

There is contamination and scale build up in the inner layers of aluminum wires. In addition, there was light-to-medium severity of wear and fretting. The broken wires found during the ½ span dissection, after the breaking load test, indicate that there may have been vibration related wear at or near the suspension assembly. Because the as-received suspension assembly was loose, the exact location at the time of installation is unknown.

Figure 1a   Outer Aluminum Wires
Circuit H24C, Conductor Tower 700 – 720

Figure 1b   Outer Aluminum Wires – Inner and Outer Surfaces
Circuit H24C, Conductor Tower 700 – 720

Figure 2a   Middle Layer Aluminum Wires
Circuit H24C, Conductor Tower 700 – 720

Figure 2b   Middle Layer Aluminum Wires – Dissected Wires
Circuit H24C, Conductor Tower 700 – 720

Figure 3a   Inner Layer Aluminum Wires
Circuit H24C, Conductor Tower 700 – 720

Figure 3b   Inner Layer Aluminum Wires – Dissected Wires
Circuit H24C, Conductor Tower 700 – 720

Figure 4a Steel Core Wires
Circuit H24C, Conductor Tower 700 – 720

Figure 4b Steel Core Wires – Dissected Wires
Circuit H24C, Conductor Tower 700 – 720

Figure 5 Broken Aluminum Wires Found in 2nd Layer, From 0 to 2.5 m from Suspension ½ Span Dissection – After Breaking Load

Figure 6 Localized Contamination Found in 2nd Layer, From 10 to 12.5 m from Suspension ½ Span Dissection – After Breaking Load

TEST S2 - TENSILE TEST (Steel and Aluminum Wires)

Objective

The objective of this test is to determine the remaining breaking strength of the aged conductor wires and to compare its value to the rated tensile strength of a new conductor.

Test Set-up

Four (4) aluminum wires from each layer and the seven (7) steel core wires were prepared from the conductor sample. The sample was about 40 cm in total length. The sample was put in the test machine so that there was greater than 30 cm distance between the grips.

The test sample used was taken from about 50 m out from the suspension clamp.

Test Procedure

The steel wire samples were preloaded to a value that was equal to an elongation of the sample of 0.10%. An extensometer was attached to the sample at the pre-load value to measure the elongation over a 250 mm gauge length. The extensionmeter was offset by 0.10% and the sample was loaded until 1.0% elongation was achieved. The load for 1.0% elongation was noted and the extensionmeter was removed. The load was increased again until failure.

Test Results

The details of the results of the Tensile Test on the individual wires are contained in Appendix D.

The calculated breaking strength of the conductor based on the tests on individual wires is listed in the table below.

Table 5 Results of Tensile Test of Individual Wires

Conductor Sample	Calculated Remaining Breaking Strength	De-rated Calculated Remaining Breaking Strength	Percent of Rated Breaking Strength (De-rated/Book Value)
H24C Tower 700 – 720, at 50 m from suspension	28,486 lbf	26,566 lbf	93.0 %

The strength of the conductor is calculated from the sum of the strength of the individual steel and aluminum wires.

As stated in the Southwire ‘Overhead Conductor Manual’, the ‘rated breaking strength’ for an ACSR conductor is the sum of the strengths of the steel and aluminum wires multiplied by the appropriate stranding factor. This ‘de-rating‘ or stranding factor is mostly attributed to the stress concentrations that occur where the wires cross each other.

The ‘de-rated measured breaking strength’ of the conductor is the aggregate sum of the strengths of the individual steel wires measured at 1.0% elongation and the breaking load of the individual aluminum wires, multiplied by the appropriate stranding factor.

Criteria

Hydro One Networks has defined end of life when the remaining tensile strength of the conductor falls below 85% of the RTS. The exception to this is that if the remaining strength is below 85% then:

i) no other tests performed on the conductor can show unsatisfactory results and
ii) the maximum tension the conductor is subjected to in the field is less than 15% RTS

Conclusion

The de-rated remaining tensile strength of the sample based on the tensile test on the individual wires is greater minimum requirement of 85% RTS, but is less than the de-rated book value. This value of remaining breaking strength is noteworthy for estimating remaining life.

TEST S3 – TORSIONAL DUCTILITY TEST (Aluminum and Steel Wires)

Objective

The objective of this test is to determine the number of torsional turns to failure for the steel wires. The complex stress-strain conditions that occur in the sample during the torsion test are sensitive to minor variations in surface condition and materials. This test is useful in assessing wire ductility under in-service loading.

Test Set-up

The length of sample is equal to 120 times the wire diameter plus the length required for clamping into the test machine. The sample is tensioned to 1% of the rated breaking strength of the wire.

The test sample used was taken from about 50 m out from the suspension clamp. This section of conductor was considered to be a typical worst-case condition.

Test Procedure

One clamp of the test machine remains stationary while the other rotates along the axis of the wire. The wire is twisted until it fails.

Test Results

The details of the results of the Torsional Ductility Tests on the individual wires are contained in Appendix D.

Four (4) aluminium wires from each layer and all seven (7) steel core wires were torsion tested. The turns to failure of the steel wire is listed in the table below.

Table 6 Results of Torsional Ductility Test of Individual Wires

Wire Number	Turns to Failure of Steel Wires
Wire 1	4.9
Wire 2	4.0
Wire 3	4.0
Wire 4	4.6
Wire 5	3.1
Wire 6	6.7
Core	3.6
Average (Wires 1 – 6)	4.6

Criteria

Hydro One Networks has defined end of life of the conductor if the average number of turns to failure of the individual steel wires (excluding the core wire) is below seven (7) turns and there are areas of excessive corrosion.

Conclusion

The average number of turns to failure of the steel wires was 4.6. According to Hydro One criteria, the steel has reached its end of life. The average value for turns to failure is noteworthy for estimating remaining life.

SUMMARY AND DISCUSSION OF RESULTS

The following table summarizes the key result obtained from each test.

Test No.	Test Name	Key Result
C1	Aeolian Vibration Endurance Test	No visible signs of any breaks or cracks of any wires.
C2	Sheave Test	No broken wires.
C3	Breaking Load Test	Percent of RTS = 91.3%
S1	Visual Examination	The steel wires had areas with no rust, with galvanizing intact. Several areas had onset of rust, with 1% to 33% of the surface in these areas covered with light rust, and negligible pitting. The aluminum wires have light to heavy contamination with no pitting. After breaking load test, ½ span dissection under suspension assembly found several broken wires in 2nd layer of aluminum wires.
S2	Tensile Test of Individual Wires	Percent of RTS = 93.0% (De-rated compared to book value)
S3	Torsional Ductility Test	Average of samples tested is 4.6 turns to failure.

The results from the **Aeolian Vibration Endurance Test** indicate that the conductor could endure at least another 40 years of vibration.

The results from the **Sheave Test** indicate that the conductor could pull in a new conductor in 40 years time without failing.

Without quantification, the results from the **Visual Examination** indicate that sections of the steel wires are in the early stages of deterioration and have not experienced a significant reduction in cross-sectional area

The **Torsional Ductility Test** average turns to failure of the six wire samples is 4.6. According to Hydro One criteria, the steel has reached its end of life. It should also be noted that there were no areas of excessive corrosion.

The results from the **Breaking Load Test on the Whole Conductor** and confirmed by the **Tensile Tests on Individual Wires** indicate that the tensile strength of the conductors has been reduced. The reduced strength may be a result of vibration related damage experienced near the suspension assembly.

CONCLUSION

Based on Kinectrics' overall interpretation of all the laboratory tests and assessments on the single conductor sample obtained from Circuit H24C, it is estimated that the conductor can remain safely in-service for at least another **three (3)** years from the date of testing without failure due to design wind and ice or vibration fatigue loads.

RECOMMENDATIONS

- Based on the analysis and assessment carried out on this section of Circuit H24C, between Towers 700 and 720, it is estimated that the conductor can remain safely in-service for a minimum of three (3) years. It is recommended that a second minimum remaining life assessment on circuit H24C be performed as soon as possible within 10 years from the time of the assessment of the first sample. If the original conductor is replaced before a second assessment is performed, then the original conductor should be reassessed anyway. This will increase the understanding of the degradation process of ageing conductors and will subsequently lead to improving the accuracy of future assessments.
- It is recommended that an atmospheric study on contamination and effects on conductor be undertaken to update the study performed in about 1990 to determine the range of the rate of deterioration. This would determine whether atmospheric conditions have improved or worsened over the past decade and would be quite useful to estimate the present rate of deterioration of the conductors.
- It is recommended that a laboratory test program be initiated with the objective to improve the understanding and to characterise the deterioration process of ACSR conductors.

Prepared by: ______________________
C. Dimnik
Engineer
Transmission and Distribution Technologies Business

Reviewed by: ______________________
C. J. Pon
Manager – Transmission Lines and Cables Dept.
Transmission and Distribution Technologies Business

Approved by: ______________________
Shahrokh Zangeneh
V.P – Marketing and Sales

DISCLAIMER

Kinectrics Inc., has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and Hydro One Networks, dated January 19, 2001.

APPENDIX A
A DISCUSSION OF REMAINING LIFE OF CONDUCTORS

TECHNIQUES FOR SCREENING AGED CONDUCTORS AND SKYWIRES

The techniques presently used to screen aged conductors and skywires for more extensive testing are:

i) Torsional Ductility Test
ii) Tension Test
iii) Visual Examination to rate the surface condition of the galvanized steel wires.

These tests have been used for many years in Hydro One to assess the condition of conductors and skywires. Those determined to be in very poor condition are either scheduled for replacement or flagged for more detailed testing. Although this approach has been effective to identify conductors and skywires in need of replacement, the techniques do not estimate the remaining physical life of conductors. To improve the management of replacement of aged conductors, their remaining life must be estimated. Other test techniques and analyses also need to be developed.

A DISCUSSION OF REMAINING LIFE OF CONDUCTORS

To begin discussions on the issue of remaining life of aged conductors, it is necessary to have a common definition and an accepted approach to estimating remaining life. These can, and probably will, carry different meanings depending on perspective. From the perspective of a test laboratory, it is limited to assessing the physical condition of the conductor against various minimum physical criteria that represent end of life conditions. From a system planning or operating perspective, requirements may dictate that a conductor be replaced before the poor physical condition dictates.

End of physical life is defined when key conductor properties do not meet specified minimum requirements. These requirements are established either to withstand extreme in-service loading conditions or to meet industry or company standards.

Remaining physical life is defined as the number of years it takes the conductor to deteriorate to the specified minimum requirements. Remaining physical life is considered to be associated with the types of gradual deterioration that are due to long-term, continuous exposure to every day mechanical, environmental and electrical loads. These loads are generally viewed as systemic and widespread and apply to the entire line.

Remaining physical life does not relate to conductor deterioration that is due to singular or transient events such as lightning, gunshots, tornadoes, etc. These types of loads are usually limited to limited number of spans. Replacement of conductor in entire line sections is not normally required in these instances.

Estimating remaining physical life of conductors based on laboratory assessment involves i) gathering information using a variety of methods and ii) interpreting this information in an appropriate manner. Some methods, however, are designed more to determine whether an aged conductor can or cannot endure a specified load condition for a specified time. The information from these methods would be used more to estimate a minimum remaining life rather than an end of life.

Minimum remaining life is defined as the minimum number of years that a conductor should continue to meet or exceed the minimum requirements. It is worth noting that it is not necessary to estimate the end of physical life. This would require an estimate of when the conductor does not meet the minimum requirements. The uncertainty associated with expressing remaining life in terms of a minimum is much less than the uncertainty in attempting to estimate when the conductor actually reaches its end of life.

Categories of minimum remaining life are shown in Table 1. The values in the table recognise two (2) issues. First, there may be instances when the conductor being tested is judged not to meet the minimum requirements. In this case, the conductor should be scheduled for replacement within the next three (3) years. Second, the number of categories of minimum remaining life must be realistic considering the inherent variability in the conductor condition, the present level of technology and information and what is really useful for managing the asset. If the conductor does meet the minimum requirements, then the minimum remaining life of the conductor is assigned as either greater than 3, 10 or 20 years.

Table 1 Categories of Estimates of Minimum Remaining Life

	Years			
Remaining Life	<3	>3	>10	>20

Generally, reassessing the conductor at some reasonable point in the future after the initial assessment will help establish the rate of conductor deterioration and will provide updated information to revise the estimate of minimum remaining life.

APPENDIX B
DESCRIPTION OF AEOLIAN VIBRATION TEST

Test Set-up and Apparatus

The set-up for the Aeolian Vibration Test is shown in Figure B-1.

The conductor was contained between two intermediate abutments. The active span cable length was about 20 m and the passive span cable length was about 10 m for a total cable length of approximately 30 m between the load pins of the deadend clamps. Fixed end abutments were used to load and maintain tension in the cable. As per IEEE Std 1138, the conductor was tensioned to 3,238 kgf or 25% of the conductor's RTS (12,950 kgf). This was applied using a cantilever weight arm on one of the end abutments.

The deadend assemblies were installed between the intermediate abutments. The original suspension assembly was supported at a height such that the static sag angle of the cable to horizontal was about 1.9 degrees in the active span and about 2.4 degrees in the passive span.

The free loop antinode amplitude of the cable was measured at the second free loop from the suspension assembly towards the shaker. An electronically controlled shaker was used to excite the cable in the vertical plane. The shaker armature was securely fastened to the cable so that it was perpendicular to the cable in the vertical plane.

Test Procedure

The initial target vibration frequency was 29.92 cps, which is the frequency produced by a 4.5 m/s wind (i.e., frequency = 830 ÷ diameter of the conductor in mm). The actual vibration frequency was the system resonance that was nearest to the target frequency and also provided good system stability.

Normally, the target free loop peak-to-peak antinode amplitude would be 9.25 mm or one third of the conductor diameter.

The conductor was subjected to 100 million vibration cycles. On completion of the Aeolian vibration test, the suspension clamp was removed and the outer aluminum wires were inspected for damage. Before removing the outer wires to inspect the steel wires, the conductor was subjected to a Sheave Test described in the next section.

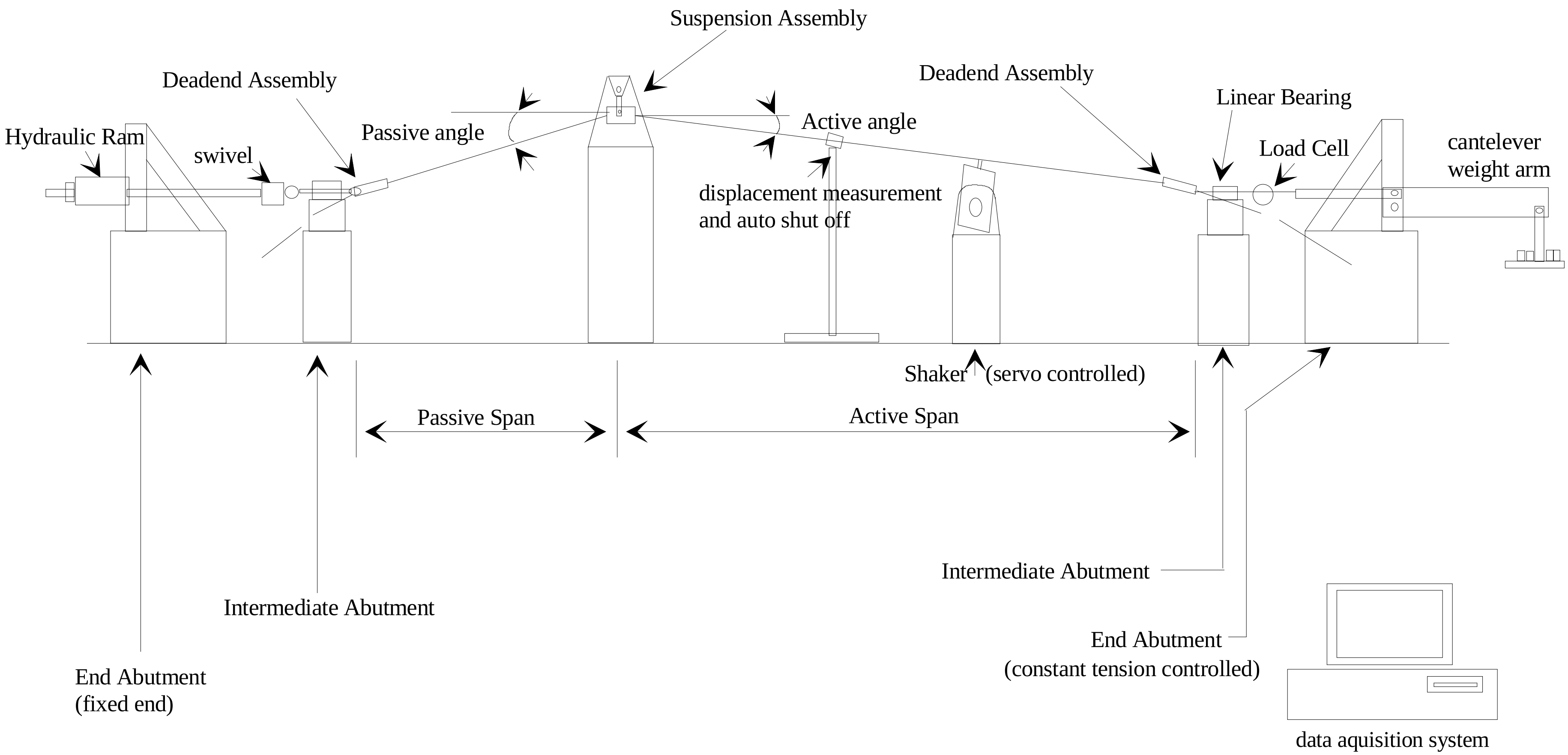


Figure B1   Set-Up for Aeolian Vibration Test

APPENDIX C

DESCRIPTION OF SHEAVE TEST

Test Set-up

The set-up for the Sheave Test is shown in Figure C-1.

Test Apparatus

The length of cable between the deadends load pins was approximately 12 m. The target tension of the cable was 3,238 kgf or 25% of the cable RTS (12,950 kgf). The inside diameter of the sheave was 713 mm. The total angle of the cable over the sheave was 31.4°. The set-up allowed 2.5 m of cable to travel through the sheave at a speed of 0.122 m/sec. A load cell was installed at one end to measure the tension in the cable.

Test Procedure

A two and a half (2.5) meter length of the cable sample was pulled 70 times forward and backward over the sheave (i.e. 35 times each way). The section of cable that passed over the sheave included the area where the suspension clamp was located.

The dissection and visual examination of the cable components within the two and a half (2.5) meter test section were performed after the test.

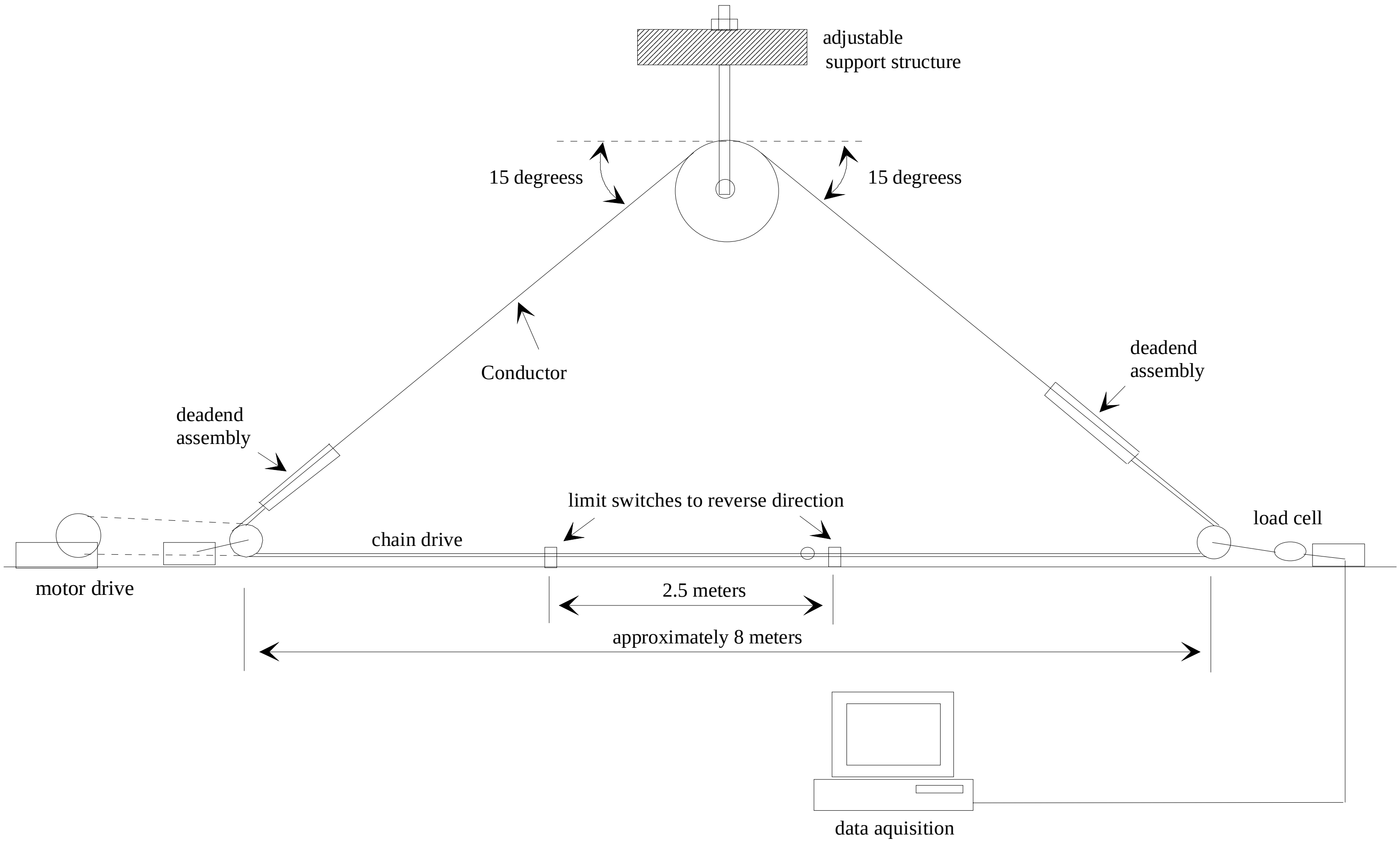
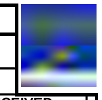


Figure C1 Set-up for Sheave Test

APPENDIX D

TENSION AND TORSION TESTS
ON ACSR CONDUCTOR FROM CIRCUIT H24C



CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 795.0 kcmil 54/7

TEST DATE : 5-Jan-2010 **TESTED by :** J. Hughes, P. Wang, T. Wales **KINECTRICS REF. NO. :** K-419095- 01

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY	RECEIVED DATE
H24C	Marine Jct. x Oshawa North Jct.	700 - 720	Not available	16-Sep-09

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 795.0 kcmil 54/7 Nom. Cable Diameter ** : 1.092 in Measured Cable Diameter : 1.085 in

	Alum. Outer Layer		Alum. Middle Layer		Alum. Inner Layer		Steel and Core Wires	
Material Tensile Strength *** :	25,000 psi	Min. Breaking Strength	25,000 psi	Min. Breaking Strength	25,000 psi	Min. Breaking Strength	205,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1213 in	for a single wire = 289 lbf	0.1213 in	for a single wire = 289 lbf	0.1213 in	for a single wire = 289 lbf	0.1213 in	Min Breaking Strength of single wire = 2,369 lbf
Area of Wire :	0.0116 sq. in		0.0116 sq. in		0.0116 sq. in		0.0116 sq. in	Min. Load @ 1% Elongation = 2,138 lbf
Number of Wires in Layer :	24		18		12		7	For Tension Test Load @ 1% Elongation **** : Preload = 255 lbf., Offset = 0.010 in.
Number of Wires Tested :	4		4		4		7	
Tension Load for Torsion Test * :	3.89 lbf = 1.764 kgf		3.89 lbf = 1.764 kgf		3.89 lbf = 1.764 kgf		24.69 lbf = 11.199 kgf	
Torsion Test sample length * :	17.06 in = (120 x dia.+ 2.5")		17.06 in = (120 x dia.+ 2.5")		17.06 in = (120 x dia.+ 2.5")		17.06 in = (120 x dia.+ 2.5")	

TEST RESULTS

Measured Wire Diameter : → (for identification only)	Alum. Outer Layer	Alum. Middle Layer	Alum. Inner Layer	Steel and Core Wires
Measured diameter	0.1205 in	0.1190 in	0.1195 in	0.1190 in (use core wire)
	The outer surface of the alum. wires had :	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: dark brown; Pitting: none; Color: dull gray	Contam: dark brown; Pitting: none; Color: dull gray	Contam: dark brown; Pitting: none; Color: shiny gray	Category [1]: 1; Rating [2]: 1; Rust: none; Pitting: none
	The outer surface had light amount of contam concentrated on ½ of conductor. The inner surface had heavy amount of contam concentrated on ½ of conductor.	The outer surface had heavy amount of contam concentrated on ½ of conductor. The inner surface had light amount of contam concentrated on ½ of conductor, was shiny gray and minor fret marks.	The outer surface had light amount of contam concentrated on ½ of conductor, dull gray areas and minor fret marks . The inner surface had light amount of contam concentrated on ½ of conductor.	The outer/inner surface was dull gray in colour, had a light amount of white contam, no rust, and zinc remaining. The core was dull gray, had a light amount of white amount of contam, with

Remaining Zinc [3] % Zinc (avg of wires 1-6) vs. Core Wire: **96%**

WIRE No.	Outer Number of Turns	Outer Breaking Strength lbf	Outer psi (calc)	Middle Number of Turns	Middle Breaking Strength lbf	Middle psi (calc)	Inner Number of Turns	Inner Breaking Strength lbf	Inner psi (calc)	Steel Number of Turns	Load @ 1% Elongation, lbf	Steel Breaking Strength lbf	Steel psi (calc)
1	35.7	261	22,585	48.6	294	25,441	58.8	303	26,220	4.9	1908	2365	204,654
2	38.4	277	23,970	65.0	292	25,268	57.6	275	23,797	4.0	1860	2251	194,789
3	51.8	301	26,047	47.6	257	22,239	61.7	290	25,095	4.0	1793	2232	193,145
4	54.6	322	27,864	41.5	292	25,268	56.2	310	26,826	4.6	1946	2373	205,346
5	-	-	-	-	-	-	-	-	-	3.1	1690	2059	178,174
6	-	-	-	-	-	-	-	-	-	6.7	1866	2334	201,971
7 (core wire)	-	-	-	-	-	-	-	-	-	3.6	1815	2234	193,318
Average (Steel & Core 'No. of Turns' is Avg. 1 to 6)	**45.1**	**290**	**25,117**	**50.7**	**284**	**24,554**	**58.6**	**295**	**25,484**	**4.6**	**1,840**	**2,264**	**195,914**

	Alum. Outer Layer	Alum. Middle Layer	Alum. Inner Layer	Steel and Core Wires
Avg. Strength x # of Wires in Layer :	(A) **6,966 lbf**	(B) **5,108 lbf**	(C) **3,534 lbf**	
Total Strength of (Aluminum/Steel) :	A+B+C=(D) **15,608 lbf**			(E) **15,848 lbf**
Calculated Total Strength of Layer :	(F) **6,934 lbf**	(G) **5,200 lbf**	(H) **3,467 lbf**	(J) **16,583 lbf**
Measured / Calculated (%) :	A/F = **100.5%**	B/G = **98.2%**	C/H = **101.9%**	E/J = **95.6%**
Total Load on Steel @ 1% Elongation :				(K) **12,878 lbf**
Total Measured Breaking Strength :	D+K=(L) **28,486 lbf**			
Derated Meas. Breaking Strength****	(M) **26,566 lbf**			
Rated Breaking Strength ** (book value) :	(N) 28,550 lbf			
Derated Strength to Book Value (%) :	M/N=(O) **93.0%**			

- Shaded areas indicate data manually entered or calculated. (Stored in : Ponc$\Conductor & Skywire Routine Testing) Photo File Number C-2009- 01

See Page 2 for Test Methods and Specifications. See Page 2 for asterisk (*) and footnote explanations.

Note : Please see 'Private Information' on Page 3.

Revision 2009-10

To : Mr. Hassan Hamzeh, Hydro One Networks Inc. Kinectrics Report No.: K-419095-RC-0001-R00 Issue Date : January 5, 2011

CONDUCTOR EXAMINATION AND TEST RESULTS - for ACSR 795.0 kcmil 54/7

TEST DATE : 5-Jan-2010 **TESTED by :** J. Hughes, P. Wang, T. Wales **KINECTRICS REF. NO. :** K-419095- 01

FIELD TAG/ASSESSMENT INFORMATION

CIRCUIT	LINE SECTION	STRUCTURE NO.	NEAREST TOWN or HIGHWAY	RECEIVED DATE
H24C	Marine Jct. x Oshawa North Jct.	700 - 720	Not available	16-Sep-09

MATERIAL DESCRIPTION (and Test Parameters)

Type : ACSR Designation : 795.0 kcmil 54/7 Nom. Cable Diameter ** : 1.092 in

	Alum. Outer Layer		**Alum. Middle Layer**		**Alum. Inner Layer**		**Steel and Core Wires**	
Material Tensile Strength *** :	25,000 psi	Min. Breaking Strength	25,000 psi	Min. Breaking Strength	25,000 psi	Min. Breaking Strength	205,000 psi	(Class A coating assumed)
Nom. Diameter of Wire ** :	0.1213 in	for a single wire = 289 lbf	0.1213 in	for a single wire = 289 lbf	0.1213 in	for a single wire = 289 lbf	0.1213 in	Min Breaking Strength of single wire = 2,369 lbf
Area of Wire :	0.0116 sq. in		0.0116 sq. in		0.0116 sq. in		0.0116 sq. in	Min. Load @ 1% Elongation = 2,080 lbf
Number of Wires in Layer :	24		18		12		7	For Tension Test Load @ 1% Elongation **** : Preload = 255 lbf., Offset = 0.01 in.
Number of Wires Tested :	4		4		4		7	
Minimum Elongation in 10", at Failure, in Percent (%) : * **	**1.7 %**		**1.7 %**		**1.7 %**		**4.0 %**	

TEST RESULTS

WIRE No.	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %	Elongation in 10 " at Failure Percent %
1	0.88	0.68	0.83	7.3
2	0.82	0.90	0.76	6.8
3	0.80	0.75	0.83	7.7
4	1.09	0.78	0.90	6.7
5	-	-	-	7.2
6	-	-	-	7.0
7 (core wire)	-	-	-	7.4
Average :	**0.90**	**0.78**	**0.83**	**7.1 (1 to 6)**

- Shaded areas indicate data manually entered or calculated. (Stored in : Ponc$\Conductor & Skywire Routine Testing)

Tension & Elongation Test Method : ASTM B557-02a for Aluminum wires & ASTM A370-03a 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 B230-99 Table 1, and for Steel wires from ASTM B498-98 Table 4.
**** Values for 1% Elongation from CSA CAN3-C49.6-M85, Table 2.
***** Derating values from Southwire Overhead Conductor Manual, Table 1-14.
Note 1 : During measurement, wire broke outside the extensiometer gauge marks, unable to obtain an elongation value.

[1] 'Category' from Table 2, Page 3, Hydro One Category.
[2] 'Rating' from Table 3, Page 3.
[3] 'Remaining Zinc' from Table 1 **(H)**, Page 3.

Revision 2009-10

NOTE : Please see "Private Information" note on Page 3.

ACSR 795.0 kcmil 54/7, CCT : H24C, Line Section : Marine Jct. x Oshawa North Jct., Structure No.: 700 - 720

TABLE 1

Remaining Zinc on Steel and Core Wires									
Measured Data					**Calculated Data**				
Wire No.	Wgt. of Wire Before Stripping (g) **(A)**	Min. Dia. Before Stripping (mm) **(B)**	Wgt. of Wire After Stripping (g) **(C)**	Min. 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	20.593	2.86	19.424	2.77	0.04	0.05	1.169	327	90
2	23.705	3.07	22.192	2.98	0.04	0.07	1.513	398	109
3	22.866	2.96	21.477	2.86	0.05	0.06	1.389	363	100
4	23.287	3.01	21.880	2.90	0.05	0.06	1.407	366	100
5	23.305	2.99	22.077	2.92	0.04	0.05	1.228	318	87
6	22.956	2.97	21.702	2.89	0.04	0.05	1.254	327	90
Avg. of 1 to 6	22.785	2.98	21.459	2.89	0.05	0.06	1.327	350	**96 (H)**
7 (core wire)	22.923	2.98	21.539	2.89	0.04	0.06	1.384	364 **(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/6030 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		
Hydro One Category	**Kinectrics Category**	**Percent of Rust by Area**
1	Stage 1	none (0 %)
2	Stage 2 a	>0 - 33 %
3	Stage 2 b	33 - 66 %
4	Stage 2 c	66 - <100 %
5	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	Medium surface rust with mild pitting
4	Heavy surface rust with mild to medium pitting
5	Heavy surface rust with medium 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.

APPENDIX E

RESULTS OF VISUAL EXAMINATION – TEST NO. S1, METHOD 2. DISSECTION ALONG ITS ENTIRE LENGTH ON ACSR CONDUCTOR FROM CIRCUIT H24C

Distance from Suspension	Severity of Discolorlation / Contamination Aluminum Outer Surface Rating					Severity of Wear Aluminum Outer Surface Rating					Comments / Number of Broken Wires
meters	**1**	**2**	**3**	**4**	**5**	**1**	**2**	**3**	**4**	**5**	
12.5				X							Localized contamination in 2nd Layer
10.0				X							Localized contamination in 2nd Layer
7.5				X							
5.0				X							
2.5				X							
0				X							**Suspension Clamp location Broken Wires found in 2nd Layer**
2.5				X							**Broken Wires found in 2nd Layer**
5.0				X							
7.5			X								
10.0				X							
12.5				X							
15.0				X							
17.5				X							
20.0				X							
22.5				X							
25.0				X							
27.5				X							
30.0				X							
32.5				X							
35.0				X							
37.5				X							
40.0				X							
42.5			X								
45.0			X								
47.5			X								
50.0			X								

Rating	Severity of Discoloration / Contamination	Rating	Severity of Wear / Pitting
1	As-new: shiny grey; no scale	1	As-new: no signs of wear
2	Light: shiny grey; no scale or contamination	2	Light signs of wear, negligible metal loss
3	Light-to-medium: slight loss of sheen; light-to-medium colour scale build-up or contamination	3	Light-to-medium: light-to-medium signs of wear (surface fret marks)
4	Medium-to-dark: complete loss of sheen with some discoloration; medium-to-dark scale build-up or contamination	4	Medium-to-dark: medium signs of wear (fret marks resulting in some metal loss or black markings)
5	Dark: dark and dull grey with discoloration; dark scale build-up	5	Dark: severe signs of wear (fret marks resulting in significant metal loss and/or broken wires; pitting)

Distance from Suspension	Extent of Rust (Steel)					Severity of Rust (Steel)					Extent of Rust (Steel Core)	Severity of Rust (Steel Core)	Comments
	Stage					Rating					Stage	Rating	
meters	1	2a	2b	2c	3	1	2	3	4	5			
12.5	X					X					1	1	
10.0	X					X					1	1	
7.5		X					X				2a	2	
5.0		X					X				2a	2	
2.5		X					X				2a	2	
0		X					X				2a	2	**Suspension Clamp location**
2.5		X					X				2a	2	
5.0		X					X				2a	2	
7.5	X					X					1	1	
10.0	X					X					1	1	
12.5		X					X				2a	2	
15.0		X					X				2a	2	
17.5		X					X				2a	2	
20.0	X					X					1	1	
22.5		X					X				2a	2	
25.0		X					X				2a	2	
27.5		X					X				2a	2	
30.0		X					X				2a	2	
32.5		X					X				2a	2	
35.0		X					X				2a	2	
37.5		X					X				2a	2	
40.0		X					X				2a	2	
42.5		X					X				2a	2	
45.0		X					X				2a	2	
47.5		X					X				2a	2	
50.0		X					X				2a	2	

Hydro One Category	Kinectrics Category	% Rust by Area on Outer Surface of Steel Wires	Rating	Severity of Rust on Outer Surface of Steel Wires
1	Stage 1	none (0 %)	1	No Rust, 100% galvanized
2	Stage 2 a	>0 - 33 %	2	Light surface rust and negligible pitting
3	Stage 2 b	33 - 66 %	3	Medium surface rust with mild pitting
4	Stage 2 c	66 - <100 %	4	Heavy surface rust with mild to medium pitting
5	Stage 3	100%	5	Heavy surface rust with medium to heavy pitting

DISTRIBUTION

Hassan Hamzeh (2)	Sustainment Investment Planning Hydro One Networks Inc. 483 Bay Street, North Tower, 15th Floor Toronto, Ontario M5G 2P5 Tel: (416) 345 5575
C.J. Pon (1)	Transmission and Distribution Technologies, KB223