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BY COURIER

August 2, 2019

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

Dear Ms. Walli:

EB-2019-0082 - Hydro One Networks Inc., Application for 2020-2022 Transmission Rates - Interrogatory Responses

Please find attached Hydro One Networks Inc. ("Hydro One")'s responses to interrogatories received in the above-noted proceeding, which have been submitted electronically using the Board's Regulatory Electronic Submission System. Two (2) hard copies will be sent to the Board.

The interrogatory responses have been organized by Intervenor as identified in Procedural Order No. 1 of this proceeding and as listed in Appendix "A" to this letter.

Please be advised that pursuant to part II, section 10 of the Ontario Energy Board Rules of Practice, Hydro One has requested confidential treatment of the information requested in the interrogatories listed in Appendix "B" to this letter, under a separate cover letter and for the reasons described in that letter.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea
Encls.
cc. EB-2019-0082 parties (electronic)

Appendix "A"

The interrogatory responses have been organized by Intervenor as follows:

Tab 1	Ontario Energy Board Staff ("OEB")
Tab 2	Energy Probe Research Foundation ("Energy Probe")
Tab 3	Association of Power Producers of Ontario ("APPrO")
Tab 4	London Property Management Association ("LPMA")
Tab 5	Canadian Manufacturers & Exporters ("CME")
Tab 6	Environmental Defence Canada Inc. ("Environmental Defence")
Tab 7	School Energy Coalition ("SEC")
Tab 8	Power Workers' Union ("PWU")
Tab 9	Anwaatin Inc. ("Anwaatin")
Tab 10	Vulnerable Energy Consumers Coalition ("VECC")
Tab 11	Consumers Council of Canada ("CCC")
Tab 12	Association of Major Power Consumers in Ontario ("AMPCO")

Appendix "B"

Hydro One has requested confidentiality treatment for the following interrogatory responses:

OEB-009
OEB-103
OEB-108
OEB-112
CME-012, Attachment 1
SEC-006
SEC-013, Attachment 1
SEC-016, Attachment 1
CCC-038, Attachment 1

OEB INTERROGATORY #1

Reference:
A-02-04-01 p.2

Interrogatory:
At the above reference, Hydro One stated the following:

The TCB[1] study included a recommendation that Hydro One reassess its performance indicators with a view to reducing cost and improving performance. Specifically, the TCB study recommended that Hydro One: (i) establish corporate goals and objectives and identify existing and new metrics that support those goals and objectives; then (ii) implement a tracking and reporting framework and incorporate the metrics into the company's performance management process. Hydro One addressed this recommendation by developing an evolved scorecard, included in TSP Section 1.5, and a Performance Reporting Governance Framework, described in TSP Section 1.5.1.

a) Have all the TCB recommendations been fully addressed by "developing an evolved scorecard" and "a Performance Reporting Governance Framework"?

b) Please explain how the proposed significant capital spending increase outlined in this filing aligns with the TCB study recommendation of "reducing cost".

c) Please explain how a new evolving scorecard will address this deficiency.

Response:
a) All the TCB recommendations in respect of performance tracking (metrics) have been addressed by Hydro One's evolved scorecard and the associated governance reporting framework.

b) The only recommendation in the TCB Study to reduce costs was in respect of administrative costs which are specifically addressed at pages 7 and 8 of Exhibit A, Tab 2, Schedule 4, Attachment 1. The study notes that many of Hydro One's other costs are below benchmark.

[1] Transmission Total Cost Benchmarking

For example:

a. Hydro One's total expenditure for transmission lines and substations was amongst the lowest in the peer group in 2014 (p. 7)
b. Hydro One's transmission lines and substations direct O&M and CAPEX was also among the lowest in the peer group in 2014 (p. 8)
c. …from a historical perspective looking at the previous five-year (2010–2014) period, Hydro One's direct O&M cost for transmission lines and substations was consistently below the median and consistent with the downward trend of the peer group (p. 8)
d. Hydro One's direct CAPEX was among the lowest of the peer group in 2014 (p. 9)
e. Looking at the direct O&M and CAPEX associated with just the transmission lines assets, Hydro One's spending was among the lowest of the peer group (p. 10)
f. Direct O&M spending by Hydro One on its transmission lines was low compared to the peer group (Figure 8). Over the previous five-year period, Hydro One was able to maintain its level of spending on a per asset basis, and its position was consistently below the median of the peer group.

c) The TCB Study does not recommend a reduction in capital costs; it is not clear what "deficiency" is referred to. As noted above, the TCB Study arrives at a different conclusion regarding Hydro One's capital spending, finding costs lower than the peer group.

OEB INTERROGATORY #2

Reference:
A-03-01 p.23 & 35
Table 7

Interrogatory:
At the first reference above, Hydro One stated the following:

Progressive Productivity savings total $286 million over the planning period and are included in the Transmission Business Plan in the form of:

1. $49 million in Progressive (Defined) savings associated with initiatives that have been identified but which have not yet been proven and verified through the productivity governance framework; and
2. $237 million in Progressive (Undefined) savings which are included as placeholder in the Business Plan to be allocated to any future initiatives that have not yet been identified.

a) Table 7 at the second reference indicates an increase of approximately 53% in System Renewal spending from 2018 to 2024. Please state what has changed since the previous Transmission Filing to justify a 53% increase in System Renewal investments.

b) Please explain in detail how the Progressive Productivity savings were calculated.

c) Please state whether or not Progressive Productivity savings targets were established in whole or in part to mitigate the magnitude of the capital spending increase.

d) Please explain how the identified Progressive Productivity savings will be achieved. For example, how does Hydro One plan to achieve the $17 million in savings scheduled for year 2020?
   i. If the $17 million in savings isn't achieved, how is that going to affect ratepayers?

e) Please explain the reasoning for the anticipated Progressive Productivity Savings on an annual basis. For example, why is $17 million in savings scheduled for year 2020 and $39 million in savings scheduled for year 2021?

Response:

a) The System Renewal plan for 2018 to 2024 is explained in detail in Exhibit B, Tab 1, Schedule 1, Section 2.2 and is necessary to address the deteriorated and at risk lines and stations assets described in that section, including unfunded work from prior applications. In general, spending in the System Renewal category is driven by the needs of customers, system reliability and overall stewardship of the transmission system. As noted in CCC-04, for several major asset classes, the proportion of the asset population which is high or very high risk as increased filing over filing.

As shown in PWU-10, parts c through f, even assuming the OEB approved Hydro One's capital plan (including the proposed System Renewal work), Hydro One will still have assets in the High Risk category by the end of the 3-year test period and even at the end of the 5-year planning period. These percentages do not account for new end of life discoveries from condition assessments during those periods..

The level of System Renewal investment proposed in this application for the years 2020 and 2021 is generally consistent with the level proposed in Hydro One's prior applications, as shown below. Note, the numbers in EB-2016-0160 have been mapped from the old OEB category of Sustainment to the new OEB category of System Renewal.

	System Renewal				
	2017	**2018**	**2019**	**2020**	**2021**
EB-2016-0160	770.4	835.1	818.7	908.5	1111.3
EB-2019-0082				865.2	1103.1

b) Please refer to Exhibit B-1-1, TSP Section 1.6 page 12. Progressive savings targets were not associated with any specific initiative or program when first established. Targets were calculated by escalating the savings commitment by 1-3% annually relative to the overall capital plan.

To quote the referenced exhibit above- "The identification and inclusion of these savings in this application represent significant incremental commitment from Hydro

One to find further efficiencies over the planning period when executing the necessary planned investments without reducing work volumes."

c) As discussed in Exhibit B-1-1, TSP Section 1.6, page 12, progressive productivity targets were established in response to the EB-2016-0160 decision to reduce the total capital plan requirements and mitigate associated rate impacts without reducing work volumes.

d) Hydro One is committed to identifying initiatives against the progressive savings target and has established a working group to actively identify savings opportunities. Additionally, Hydro One has demonstrated the commitment to finding the savings by associating the approved productivity targets to management compensation as a component of short and long term incentive plans.

The benefit to the ratepayer is discussed in to Exhibit B-1-1, TSP Section 1.6 page 12 and provided below:

"Hydro One has given the benefit of these savings to ratepayers up front and has taken on the execution risk to deliver its planned work program within a reduced funding envelope. As initiatives are defined, they will be reviewed in line with Hydro One's productivity governance framework and, if approved, the savings will be tracked and credited as an achievement by the project against the savings target."

e) Please refer to part b)

OEB INTERROGATORY #3

Reference:

A-03-01 p.33-37

Interrogatory:

At the above noted reference, Hydro One stated the following:

While the planned rate of refurbishment does not keep up with lines demographics, the risk is managed by prioritizing line refurbishment investments based on detailed asset condition assessments. The pace at which a transmission line deteriorates varies depending on location and environmental and system conditions.

a) Does Hydro One's assessment of expected service life for specific transmission lines incorporate these factors? In other words, are transmission lines in areas with favourable locations, environmental and system conditions that would reduce deterioration assigned an extended service life?

b) What is the bookend range of ESL variability, from less favourable to more favourable locations?

Response:

a) No, Hydro One uses a single expected service life for each conductor type as provided in Exhibit B-1-1, TSP Section 2.2.2.1 page 55.

b) Please refer to a).

OEB INTERROGATORY #4

Reference:
A-03-01 p.39
Figure 4 Scorecard

Interrogatory:

a) Has Hydro One considered implementing a scorecard metric detailing the percent of projects completed as per plan? If not, why not?

b) Has Hydro One considered implementing a scorecard metric detailing the actual versus planned expenditures for the planned projects? If not, why not?

Response:

a) Hydro One tracks the percent of projects that are completed within the year indicated in the investment plan. This is reviewed monthly with the management team. This monitoring and reporting is independent of the Evolved Electricity Transmitter Scorecard.

b) Hydro One monitors the cost performance for each project that is in execution including through monthly reviews by the management team. This monitoring and reporting is independent of the Evolved Electricity Transmitter Scorecard. Hydro One is in the process of implementing additional metrics regarding individual project performance reporting to complement those existing on the referenced scorecard which are primarily focused on the overall capital envelope and associated outcomes.

Witness: Andrew Spencer

OEB INTERROGATORY #5

Reference:

A-04-01 p.1-3

Handbook for Utility Rate Applications, October 13, 2016

Interrogatory:

Hydro One's 3-year Custom IR plan consists of rebasing the revenue requirement for 2020 through a cost of service approach, based on forecasted 2020 test year capital and operating costs. After rebasing the revenue in 2020 on a Cost of Service basis, Hydro One proposes a Custom Incentive Rate-Setting approach based on a Revenue Cap IR for the following two years (2021 and 2022). The revenue requirement for the rate year t is equal to the revenue requirement in year t-1 adjusted annually by the revenue cap index (RCI):

$$RR_t = RR_{t-1} \times (1 + RCI_t)$$

where:

$$RCI_t = I_t - (X + stretch) + C_t \pm Z_t$$

- I_t is the Inflation (i.e., Input Price Inflation or IPI), as determined annually by the OEB for the following rate year. Hydro One proposes an electricity transmission sector-specific inflation factor based on an analysis documented in PSE's evidence
- X is the base productivity factor representing the historical sector annual productivity trend.
- $stretch$ is a stretch factor to ensure a sharing of benefits of improved productivity and cost performance between shareholders and ratepayers over the plan term.
- $C_t$is Hydro One's Custom Capital Factor, determined to recover the incremental capital-related revenue requirement in each rate year necessary to support Hydro One's proposed Transmission System Plan, beyond the amount already recovered in the revenue cap-adjusted revenue requirement for that year
- Z is for any qualifying adjustment(s) for recovery of (capital and/or operating expense) for exogenous factors (e.g., major storm damage recovery, policy changes) that meet the OEB's requirement for Z-factors.

Hydro One has not included a growth ("g") factor in its revenue cap proposal, on the basis that there is little change in the transmission load forecast (and hence on the cost allocation of the charge determinants to be used for determining the Uniform

Transmission Rates (UTRs) to recover the aggregate revenue requirements of all transmitters for each year.

Based on the Total Factor Productivity and total cost benchmarking analyses in the evidence of Power Systems Engineering Inc. (PSE), Hydro One has proposed base X and stretch factors of 0% and 0%. Thus, as proposed, Hydro One's Custom IR revenue requirement adjustment would be:

$$RevReqt_t = RevReqt_{t-1} \times (1 + (IPI_t^{Tx} - (0\% + 0\%) + C_t \pm Z_t))$$

a) Please confirm that, as proposed with a 0% base X and stretch factors, there are no productivity gain expectations in the 3-year Custom IR plan except for any that might be factored into the rebased revenue requirement for 2020. In the alternative, please explain.

b) In the OEB's Handbook for Utility Rate Applications (Rate Handbook), the OEB states the following:

- Custom IR: Under this methodology, rates are set for five years considering a five-year forecast of the utility's costs and sales volumes. This method is intended to be customized to fit the specific utility's circumstances, but expected productivity gains will be explicitly included in the rate adjustment mechanism. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations. Additional guidance on Custom IR applications is set out below.[1]

With the proposed X and stretch factors set at 0%, please explain how the revenue cap adjustment satisfies the OEB's expectation in the Rate Handbook that "expected productivity gains will be explicitly included in the rate adjustment mechanism."

c) As proposed, the revenue requirement adjustment formula escalates OM&A by inflation, while the capital-related revenue requirement is adjusted by inflation and by the C-factor accounting for all forecasted capital additions per the Transmission System Plan beyond the inflation adjustment. Isn't Hydro One's Custom IR plan, as proposed, equivalent to a 3-year cost of service plan (i.e., with the revenue requirement rebased through a cost of service approach for 2020, with formulaic

[1] Handbook for Utility Rate Applications, October 13, 2016, p. 24

adjustments for inflation on OM&A and inflation and capex growth on the capital-related revenue requirement for 2021 and 2022). Please explain your response.

d) The OEB provides further discussion on the Custom IR plan expectations in the Rate Handbook:

- Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. *Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).*[2] **[Italics added]**

Please explain how Hydro One's proposed revenue cap formula satisfies the emphasized section of the OEB's policy.

Response:

a) As indicated in Exhibit A, Tab 4, Schedule 1, Hydro One's proposal is based on a Productivity Factor (X) that is equal to the sum of Hydro One's Custom Industry Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor. Based on PSE's study, Hydro One's proposed Productivity Factor of 0% reflects the sum of the Custom Industry Total Factor Productivity (TFP) measure of 0% and a Custom Productivity Stretch Factor specific to Hydro One of 0%.

Although PSE determined that the electricity transmission industry TFP is -1.45%, a proposed Custom Industry Factor Productivity measure of 0% was proposed consistent with the OEB's findings in 4th generation IRM for electricity distributors. The decision to utilize a 0% Custom Industry Factor Productivity instead of a -1.45% as calculated, imposes a 1.45% implicit stretch factor on Hydro One as outlined in PSE's report. The proposed stretch factor of 0% is assigned based on the results of PSE's total cost benchmarking study and reflects appropriate productivity gains expectations as established by the OEB under 4th generation IRM for utilities that have demonstrated total cost performance similar to that of Hydro One.

[2] Ibid., p. 25

Additionally, significant productivity savings have been embedded in the 2020 OM&A forecast and 2020-2022 Capital Plan. Hydro One has challenged itself to find further productivity gains and included in this application additional progressive productivity savings as discussed further in Exhibit A, Tab 3, Schedule 1 and Section 1.6 of the TSP. Hydro One's commitment to these savings in the Application is to the benefit of ratepayers because the capital expenses underpinning the proposed revenue requirements are reduced by these amounts.

b) Please refer to part a) above.

c) Hydro One's Custom IR proposal differs from a 3-year cost of service plan in several ways. Firstly, the proposal is based on a mechanistic index that includes the productivity gains expectations outlined in part a) of this response. Unlike multi-year cost of service applications, the cost of capital is not updated annually. Once calculated in this proceeding, the Capital Factors will not change in future years and therefore future revenue will vary due to changes in the inflation factor. Further, as discussed in Exhibit A, Tab 4, Schedule 1 the current application has proposed additional Custom IR features that protect rate payers which include an Earning Sharing Mechanism (ESM) and the Capital In-Service Variance Account (CISVA).

d) As indicated in Exhibit A, Tab 4, Schedule 1 the revenue requirement for 2021 and 2022 are derived using Custom Revenue Cap Index (RCI) RCI = I – X + C. Part a) above provides discussion on what type of productivity measures are built into the proposed revenue requirement as well as the implicit stretch factor which is imposed through the adoption of the proposed 0% Custom Industry Total Factor Productivity (TFP).

OEB INTERROGATORY #6

Reference:
A-04-01
Decision with Reasons EB-2017-0049, March 7, 2019, pp. 31-33
Decision and Order EB-2018-0218, June 20, 2019, pp. 19-21

Interrogatory:
OEB staff notes that the proposed Custom IR plan, with respect to the adjustment formula for Hydro One's revenue requirement for the years 2021 and 2022, is similar in many respects, to Hydro One's current distribution Custom IR plan approved in EB-2017-0049, including the inclusion of a C-factor, and to Hydro One SSM's revenue cap plan for 2019-2026 recently considered and decided upon in EB-2018-0218.

a) Hydro One proposed a similar "revenue cap" adjustment formula, including a Custom Capital Factor (C-Factor) for its 5-year Custom IR plan (2018-2022) for distribution rate-setting in an earlier application (EB-2017-0049). The plan had distribution specific inflation, base X and stretch factors, and also differed in that the plan adjusted distribution rates rather than the aggregate revenue requirement.

   In its Decision with Reasons EB-2017-0049, the OEB determined that the stretch factor of 0.45% proposed should apply to the revenue cap index for adjusting Hydro One's distribution rates during the plan term, from 2018 to 2022. The OEB also determined that an incremental stretch factor of 0.15% should be included into the C-factor calculation, to incentivize further capital-related efficiencies for the capital program as forecasted in the Distribution System Plan (analogous to the Transmission System Plan filed in this application). This incremental 0.15% stretch factor was in addition to the 0.45% stretch factor approved for the rate adjustment formula and applied to both capital and OM&A.

   Please provide Hydro One's views, with its reasons, on whether on an additional (incremental) stretch factor would be appropriate to provide an incentive for Hydro One to seek further efficiencies in its transmission capital program during the term of this Custom IR plan, similar to what the OEB approved for Hydro One's distribution operations.

b) On June 20, 2019, the OEB issued its Decision and Order pertaining to a multi-year revenue cap plan for the period 2019 to 2026 for Hydro One Sault Ste. Marie LP (Hydro One SSM). Hydro One SSM is an affiliated electricity transmission utility operating around Sault Ste. Marie, formed following the acquisition of Great Lakes Power Limited. In this decision the OEB determined that:

The OEB approves the proposed productivity factor of 0%, a factor indicative of the change in productivity expected for the transmission sector as a whole. No party argued for a negative productivity factor even though both PSE and PEG calculated a negative TFP.

…

The OEB approves a stretch factor of 0.3% to provide an incentive to Hydro One SSM beyond the rate of inflation and balance the needs of its customers and shareholders during the term of the revenue cap framework.

This stretch factor finding was made independent of the acquisition by Hydro One Inc. and the existence of a deferred rebasing period. Clearly, capital and OM&A savings are expected to result from the integration of Hydro One SSM into Hydro One Networks that is underway in 2019. The OEB finds that a stretch factor of 0.3% provides incentives to find further efficiency improvement beyond those proposed by the acquisition.

OEB staff acknowledge that the OEB's findings with respect to Hydro One SSM's revenue cap plan specifically pertain solely to that utility and that plan. However, Hydro One's proposed Custom IR is similar to the Hydro One SSM revenue cap plan, except for the inclusion of the C-factor in place of any ICMs, and is largely supported by PSE's slightly updated report. Please provide Hydro One's views on why a positive, non-zero stretch factor to incentivize further efficiency improvements would not be preferable to its proposed 0% stretch factor.

<u>Response:</u>

a) As stated in Exhibit I, Tab 01, Schedule OEB-5 part a), the current Transmission Application includes an implicit stretch factor which is significant in nature (1.45%) unlike the Distribution application. The implicit stretch factor is as a result of the transmission industry displaying significant negative productivity. Although PSE determined that an electricity transmission industry TFP is -1.45%, the proposed Custom Industry Factor Productivity measure of 0% was proposed consistent with the OEB's findings for distributors in 4th generation IRM.

Moreover, unlike the Hydro One Distribution application which only included productivity savings based on defined initiatives, the current Transmission Application includes in savings in addition to those based on defined initiatives, in the form of progressive productivity savings. Progressive productivity savings represent a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes. Progressive productivity savings are further described in Section 1.6 of the TSP.

b) Given that the PSE study in the HOSSM application was conducted for the purpose of Hydro One Transmission, Hydro One Transmission believes that implementing the findings of the PSE study is appropriate (specifically the Custom Productivity Factor of 0%).

As stated in the HOSSM decision on page 20:

The PSE and PEG evidence for electricity transmission utilities provided in this proceeding was based primarily on 43 U.S. utilities with the only Canadian utility being Hydro One Networks. Given the absence of sufficient Canadian data and utilities the size of Hydro One SSM, the OEB finds neither study appropriate to determine the stretch factor for Hydro One SSM, a small Canadian transmission utility. In the absence of applicable evidence, regardless of the reason, the OEB must rely upon its judgement and experience in incentive regulation to establish a stretch factor.

Additionally, on page 20 of the decision is stated further that:

The OEB has applied a 0% stretch factor to certain electricity distributors based on their total cost performance as benchmarked against other distributors in Ontario. The most efficient distributor is assigned the lowest stretch factor of 0%. Conversely, a higher stretch factor, up to 0.60%, is applied to a less efficient distributor to reflect the incremental productivity gains that the distributor is expected to achieve. The OEB finds no evidence to justify a 0% stretch factor for Hydro One SSM, implying it is the most efficient transmitter.

Based on the sections above, it is evident that the reasons a stretch factor of 0.3% was imposed in the HOSSM proceeding are not applicable to Hydro One Transmission.

In the HOSSM case, PSE's and PEG's results did not directly pertain to SSM but instead were evaluations of Hydro One Network's total cost performance. The dataset does include utilities the size of Hydro One Networks and there is substantial evidence to justify a 0% stretch factor for Hydro One Networks in this application. PSE's total cost benchmarking results reveal that Hydro One Networks costs are 27.1% below the benchmark expectations implying a 0% stretch factor. PEG's recent results for Hydro One Networks in the SSM application implied a 0.15% stretch factor.

OEB INTERROGATORY #7

Reference:
A-04-01-01, A-02-04-01
EB-2016-0160, Exhibit B2/Tab 2/Schedule 1

Interrogatory:
PSE has included a sample of U.S. utilities for its TFP and Total Cost Benchmarking analyses. In its evidence filed in EB-2018-0218 and the updated evidence filed in this application, PSE states that it was unable to get the necessary data from other Canadian transmitters that it contacted.[1]

On Hydro One's previous transmission rate application, Hydro One commissioned Navigant Consulting Ltd (Navigant). To undertake a total cost benchmarking study. This was filed as Exhibit B2/Tab 2/Schedule 1.

Navigant's study is different in nature from PSE's methodology. Navigant's approach is not econometric; Navigant did not attempt to estimate a cost function. Instead, it examined capital and operating costs at various levels and for certain categories. Reliability data were included, but business condition variables were largely omitted. Costs were normalized per "asset", and assessment of cost performance was qualitative in nature. However, OEB staff observes that Navigant's study includes, in addition to a sample of U.S. utilities, two other Canadian utilities with electricity transmission assets and operations, specifically Manitoba Hydro and B.C. Hydro.

a) Please provide further explanation on the efforts to obtain data from Canadian electricity transmitters, and why Navigant was able to do so while PSE was not.

Response:
a) Please see page 21 of PSE's report. Participation would have required that the utilities provide the same cost and explanatory variable information used in our study. Some utilities asked for the data request and then decided to not participate. We do not know why the utilities made this decision.

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1 Exhibit A/Tab 4/Schedule 1/Attachment 1/p. 21/section 3.1.2. In EB-2018-0218, PSE was asked an interrogatory seeking further explanation of the attempt to include other Canadian utilities with electricity transmission assets and operations in its sample – see EB-2018-0218 OEB Staff Interrogatory # 64 (Exhibit I/Tab 1/Schedule 64).

OEB INTERROGATORY #8

Reference:

A-04-01-01 p.5,7,17 & 21
EB-2018-0218, OEB Staff IR 59 (Exhibit I/Tab 1/Schedule 59)
EB-2018-0218 Revised Public Redacted Technical Conference Transcript Volume 2 (January 15, 2019), p. 39/l. 6 to p. 162/l. 14
Decision and Order EB-2018-0218, p. 21
EB-2018-0218 Exhibit I/Tab 1/Schedule 65 (OEB Staff IR # 65)
EB-2018-0218 JT2.8
EB-2018-0218 JT2.9

Interrogatory:

On page 5 of its evidence, PSE notes the following changes have been made to its methodology in its evidence from that filed in the Hydro One Sault Ste. Marie revenue cap application:

This report has been revised from the Power System Engineering, Inc. (PSE) report filed in the Hydro One Sault Ste. Marie LP (SSM) application found in EB-2018-0218. Our recommendations regarding the customer incentive regulation parameters remain unchanged and our findings are similar to the report previously filed. No changes to the study have been made except the modifications which are listed and explained below.

1. Hydro One Networks provided PSE with a revised business plan that includes modified OM&A and capital spending levels for the projected years of the study.

2. A second modification has occurred due to PSE identifying peak demand data that was incorrectly reported by the three Southern Companies (Alabama Power, Gulf Power, and Mississippi Power) included in the sample. This data has now been corrected.[1]

3. The third modification are slight revisions in plant additions in 2016 and 2017 made by Hydro One.

4. The incentive regulation period moves to 2020 to 2022 which means the OM&A spending is now escalated for 2021 and 2022 by I-X using the 2020 test year expenses rather than 2019.

5. Two minor corrections in the code were made relative to the prior research. The first is we are now calculating the asset prices prior to 1963 in calculating the capital benchmarks. The second is including only the observations in the TFP sample when aggregating the TFP components.[2]
These five modifications have been incorporated into this revision and are the only changes made to the dataset and study methodology relative to the research filed EB-2018-0218 and EB-2018-0130.

6. This adjustment moved the TFP annual trend upwards by around 0.42%.

7. Both corrections had a minimal impact on the results with the effect of the change being a slightly lower TFP trend by around 0.16%.

PSE notes on page 17 of its evidence that the long-term TFP trend is -1.45%, a change of -0.16 percentage points from the study filed in EB-2018-0218. The historical data range for the TFP analysis was unchanged, from 2004 to 2016, as noted on page 7 of PSE's evidence.

a) Please confirm that only the changes in bullets 2, 3 (with respect to 2016 capital additions for Hydro One), and 5 relate to PSE's TFP analysis.

b) Please explain why PSE did not update its TFP and total cost benchmarking analysis with an additional year of data of 2017 actuals for both Hydro One Networks and the U.S. sample.

c) In its analyses documented in its evidence filed in this Application and in Hydro One SSM's application in EB-2018-0218, PSE has introduced a new constructed variable which it terms as a "loading" or "engineering construction index" to measure regional standards for the physical construction of networks to withstand climactic extremes for wind speeds, storms, ice loading, etc. OEB staff have used the term "hardening" as "loading" can also be used in the context of capacity or over-loading of electrical equipment.

In the EB-2018-0218 Decision and Order with respect to Hydro One SSM's revenue cap plan, the OEB stated:

The OEB reserves judgement on the new "construction standards index" variable[57] provided in the PSE Report. This new variable is worthy of further consideration, yet the concept was not fully vetted in this proceeding. Further, the OEB questions its relevance to Hydro One SSM and its asset base.

[57] PSE defines this new variable in Exhibit D, Tab 1, Schedule 1, pp. 25-26 and Appendix A. OEB staff used the term "hardening" variable, as it refers to the engineering standard to which network infrastructure must be constructed to withstand climactic conditions, such as wind and ice, in different regions (OEB staff submission, April 12, 2019, pp. 28-29).

OEB staff recognizes that Decision and Order EB-2018-0218 was issued on June 20. 2019, after the filing of Hydro One's current Application. However, there was testing of this new variable during the EB-2018-0218 case, through interrogatories and during the Technical Conference. In particular, OEB staff raised a concern regarding the construction of the variable for Hydro One in that, based on Platts' GIS mapping, where all, or nearly all, of Ontario is used, while Hydro One has few or no transmission assets in a large portion of northern Ontario.

d) Please explain why PSE (or Hydro One) did not update the "hardening" variable in light of the record in EB-2018-0218.

e) Please confirm that item 2 of the changes noted on page 5 of the updated PSE report correspond to the problem identified in OEB Staff Interrogatory #65 from the SSM proceeding.

f) Please confirm that item 5 of the changes noted on page 5 correspond to the problems identified in undertakings JT2.8 (aggregation) and JT2.9 (asset price) from the Hydro One SSM technical conference.

<u>Response:</u>

a) Confirmed. The changes in bullets 2, 3 (with respect to 2016 capital additions for Hydro One), and 5 relate to PSE's Industry TFP analysis. Note, this does not apply to the Hydro One TFP analysis through to 2022.

b) When PSE prepared its report for this proceeding, and given the nature of the report (as a follow-up to the report in EB-2018-0218), it did not seem necessary to update it for the 2017 actual data for the sample utilities at that time. In EB-2018-0218 both the PSE and PEG studies and reports used 2016 as the most recent year of actual data for the sample utilities. The study could be updated for the more recent actual data, as necessary. PSE would be prepared to do so, but significant additional time would be required given the scope of work involved.

c) PSE did examine the transmission loading variable to see what the impact on the variable value may be if it was calculated based on the location of Hydro One's transmission lines rather than service territory. We found that the variable value for Hydro One would increase if the methodology were modified. In other words, the cost challenges to Hydro One due to the loading variable would increase if we modified the methodology. This likely would raise Hydro One's total cost benchmark and improve the benchmarking score.

d) However, we did not believe it was appropriate to modify the variable from what was used in EB-2018-0218 because of consistency concerns with the rest of the sample. Since we cannot institute a change from service territory mapping to transmission line mapping for the rest of the sample, we chose to continue to be consistent in calculating the variable between Hydro One and the sampled utilities using the designated service territory mappings as the basis for the variable.

e) Confirmed. Please note PSE's response in part b of OEB Staff Interrogatory #65.

f) Confirmed.

OEB INTERROGATORY #9

Reference:
A-04-01-01
"Working Papers" for PSE Report filed as Attachment D/Tab 1/Schedule 1/Attachment 1 in EB-2018-0218

Interrogatory:
PSE has filed a report on the Total Factor Productivity and total cost benchmarking comparing Hydro One's transmission operations with a sample of U.S. utilities. The report is an update of similar evidence filed in the Hydro One SSM case (EB-2018-0218), with the changes documented of the PSE Report filed in this Application.

In EB-2018-0218, Hydro One, on behalf of its consultant, PSE, provided to parties the "working papers" (i.e., the data, models and other documentation) to allow requesting parties to understand and replicate the analyses documented in PSE's Report as filed in that case.

Please provide PSE's updated "working papers" with the data, models, and documentation to reflect the updated analyses documented in PSE's evidence in this current application.

Response:
The requested PSE working papers are being provided pursuant to the Board's Practice Direction on Confidential Filings, due to the commercially sensitive nature and third party data being requested.

OEB INTERROGATORY #10

Reference:

A-04-01-01 p.19

Interrogatory:

On page 19 of its evidence, PSE states the following as one of the reasons for recommending that the Custom IR "revenue cap" formula not include a growth factor:

The existence of the capital factor is another reason we recommend not including the output growth factor in the formula. The capital factor incorporates any expected capital costs resulting from output growth. This makes including the output factor somewhat redundant when the capital factor is also present in the formula. However, PSE felt it was important to mention this output growth term in the discussion, for the sake of accuracy and completeness. In the case of a revenue cap formula where the output growth factor is not expected to be zero and a capital factor is not present, an output growth factor should be included in a revenue adjustment formula.

a) Is PSE stating that, with the custom capital factor increasing the annual allowed revenue requirement beyond what the standard I – X (inflation less productivity) formula would give, "growth" in demand for transmission services is *implicitly* factored in to Hydro One' proposed Custom IR formula? In the alternative, please explain.

b) If PSE believes that growth in demand is implicitly factored into the revenue requirement through the custom capital factor, does PSE also believe that, for the determination of Uniform Transmission Rates (UTRs) that aggregate the annual allowed revenue requirements of all involved Ontario electricity transmitters, it is also necessary to ensure that the charge determinants for the UTRs should also be adjusted to take into account the annual forecasted growth? Please explain your response.

c) If the response to b) is in the positive, please provide PSE's views on how Hydro One should forecast the charge determinants for its portion of the aggregate transmission revenue requirement on which the UTRs are calculated, to correspond with the growth factored into the C-factor-adjusted revenue requirement for each of 2021 and 2022.

Witness: Steve Fenrick

Response:

a) If there was growth in the components of the output quantity index (maximum peak demand and kilometres of transmission lines) then it would be our assumption the capital needs resulting from that growth would be reflected in the capital request of the company. Nonetheless, the output quantity index growth is projected to be essentially zero during the Custom IR period.

b) The specific determination and any adjustment of UTRs is beyond the scope of PSE's mandate. We note that in PSE's output quantity index the growth rate is essentially zero during the Custom IR period. Hydro One notes that it is seeking approval for the test year billing determinants as outlined in Table 5 of Exhibit A, Tab 3, Schedule 1. Hydro One expects that the billing determinants used for the determination of UTRs in each year of the Custom IR period will reflect the appropriate year of the 3-year forecast approved in this proceeding.

c) Please see response to part b)

OEB INTERROGATORY #11

Reference:
A-04-01 p.10-11
Capital In-Service Variance Account

Interrogatory:
In Section 2.2 of this Exhibit, Hydro One has proposed a Capital In-Service Variance Account (CISVA) as a component of its proposed Custom IR plan. Hydro One proposes that the CISVA have the following features:[1]

1. The account will track the impact on revenue requirement of any in-service additions that are on a cumulative basis 98% or lower of the OEB-approved amount for each year of the Custom IR term;
2. For cumulative in-service additions that are 98% or lower of the OEB-approved level, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account; and
3. At the end of the three-year term of the Custom IR Plan, in 2022, the sum of the variances in each year will be disposed of for the benefit of customers with the following conditions;
    - Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and
    - Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry will be made in the variance account and no amount will be recoverable from ratepayers

a) Is Hydro One's proposal for the CISVA that same as Hydro One Networks proposed in its most recent distribution Custom IR plan in EB-2017-0049? Is it the same as the OEB approved in its Decision with Reasons EB-2017-0049? Please document any differences.
b) Hydro One has proposed a Custom IR revenue requirement adjustment with X = 0 (both base productivity and stretch factors are 0, as supported by PSE in its report). If

[1] Exhibit A/Tab 4/Schedule 1/pp. 10-11

the Custom IR plan is approved as proposed, please explain how the first condition of item 3) will be calculated:

- Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation

What will be "verifiable productivity gains"?

Response:

a) The mechanics of Hydro One's proposal for a Capital In-Service Variance Account (CISVA) are largely the same as was previously proposed and approved in the Hydro One Distribution application.

b) Hydro One is proposing a CISVA with several key features as discussed further in Exhibit A, Tab 4, Schedule 1 pages 10-11. One such feature is that revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation of the CISVA. Verifiable productivity gains refer to additional capital-related productivity gains beyond those identified and included in the current revenue requirement (current revenue requirement includes specific productivity savings and progressive productivity savings) in order to ensure that further productivity savings are incented throughout the term of the custom IR period. The process associated with achieving and quantifying verifiable savings places the onus on Hydro One to prove the achievement of these savings in future rate proceedings. Further details regarding the process for identifying and measuring verifiable productivity gains are provided in Section 1.6 of the TSP.

OEB INTERROGATORY #12

Reference:
A-04-01-01

Interrogatory:
PEG may wish to exclude certain operation, maintenance, and administrative ("OM&A") expenses from the US data that they use in this proceeding out of concerns about structural changes in the U.S. transmission industry. They may need to remove analogous costs from Hydro One's expenses. The excluded costs include those for load dispatching and system planning, which are often handled by regional transmission organizations and other independent system operators.

a) For all years covered by the PSE study, please provide estimates of Hydro One's OM&A costs that are included in the PSE study which correspond to the following FERC accounts. We provide the RRR account numbers that we believe might match the FERC accounts excluded from the PEG study. The list includes the miscellaneous account, where sizable restructuring and/or RTO costs have occasionally been recorded. If Hydro One does not wish to provide a more exact customized calculation, providing data for each of the suggested RRR accounts will be sufficient. PEG does not need itemization of the various 561 and 569 accounts for Hydro One; a total for these accounts would suffice.
   - Account 561: Load Dispatching (RRR account 4810)
   - Account 561.1: Load Dispatch-Reliability (RRR account 4715 or 4810)
   - Account 561.2: Load Dispatch-Monitor and Operate Transmission System (RRR account 4715 or 4810)
   - Account 561.3: Load Dispatch-Transmission Service and Scheduling (RRR account 4715 or 4810)
   - Account 561.4: Scheduling, System Control and Dispatch Services (RRR account 4715 or 4810)
   - Account 561.5: Reliability, Planning and Standards Development (RRR account 4715 or 4810)
   - Account 561.6: Transmission Service Studies (RRR account 4715 or 4810)
   - Account 561.7: Generation Interconnection Studies (RRR account 4715 or 4810)
   - Account 561.8: Reliability, Planning and Standards Development Services (RRR account 4715 or 4810)

Witness: Steve Fenrick

- Account 566: Miscellaneous Transmission Expenses (RRR account 4845)
- Account 567: Rents (RRR account 4850)
- Account 569.4: Maintenance of Miscellaneous Regional Transmission Plant (RRR account 4715 (RRR account 4715 or 4810))

Response:

Hydro One is in the process of determining what information is available for all years of the study and will provide such information when available.

OEB INTERROGATORY #13

Reference:

A-04-01-01 p. 31

EB-2018-0165 Exhibit L3/Tab 1/Schedule 2 (Interrogatory OEB Staff-2 on PSE's Reply Report filed in the Toronto Hydro-Electric System Limited 2020-2024 Custom IR proceeding)

Interrogatory:

PSE states the following on page 31 of their report:

We determined the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans' Heavy Construction Cost Data.

In their response to L3-Staff-2 in EB-2018-0165 PSE stated:

PSE has a paper copy of the 2012 book. The page containing the year of the data underlying the City Cost Indexes states: "Index figures for both material and installation are based on the 30 major city average of 100 and represent the cost relationship as of July 1, 2011." PSE used the 2012 RSMeans book to levelize the capital in the year 2012.

a) Please confirm that, for its work in this proceeding, PSE used the 2012 RSMeans book data to levelize its costs in 2012. In the alternative, please provide a similar discussion from the RSMeans book that PSE used for its work in this proceeding.

Response:

a) Confirmed. Given PSE's consistent treatment using the same asset price escalator for both Hydro One and the rest of the sample (we used Handy-Whitman indexes specific to the electric transmission industry for all sampled utilities), whether we conducted the capital levelization in 2012 (the year of the RSMeans publication) or 2011 (the year the data was based on) will have a negligible impact on the Hydro One total cost benchmarking results and no impact on the TFP analysis.

OEB INTERROGATORY #14

Reference:
EB-2018-0218, I-01-72

Interrogatory:
In part e) a) of this interrogatory response on PSE's report filed in the Hydro One Sault Ste. Marie revenue cap plan application (EB-2018-0218), PSE states that:

Yes, PSE …has used the Driscoll-Kraay approach to correct for autocorrelation within the sample. As stated in Section 3.4.2 of the PSE report, this correction for autocorrelation does not alter the underlying coefficient values and thus does not alter the benchmark result. PSE uses the Driscoll-Kraay standard errors to test statistical significance of the included variables, but this does not alter the estimates themselves.

In part e) b) of the same interrogatory response, PSE states that:

PSE used the standard Driscoll-Kraay approach to correct for autocorrelation in the standard errors found in the STATA software package. No choice was made, nor is one available to be made for a specific time period.

In part h) of the interrogatory response, PSE lists steps in order to replicate their model:

PSE only used STATA to estimate the Driscoll-Kraay standard errors. The working papers contain all of the code PSE has for STATA. If one is trying to re-produce the STATA results, the steps to produce the STATA results are 1) import the data, 2) declare the data to be a panel dataset, 3) create the variables needed for the regression, and 4) use the Driscoll-Kraay procedure with the command "xtscc".

Here "xtscc" is a command in the STATA econometric software package.

a) Please confirm that correcting for autocorrelation (if present) is necessary in econometric benchmarking for unbiased standard errors and valid t-stats.

b) In attempting to replicate PSE's model, PEG implemented the "xtscc" command in STATA but seeks further clarification regarding the command options that PSE used.

Please confirm that STATA allows the "xtscc" user to specify the number of periods up to which the residuals may be autocorrelated with the lag(#) option. For example, if the user enters "lag(1)", then the package implements an MA(1) autocorrelation correction. Given that PSE originally said "no choice was made, nor is one available to be made for a specific time period," did PSE not specify this option? If not specified, what is the command's default?

Response:

a) PSE did correct for autocorrelation in the study. Correcting for autocorrelation (if present) can produce more precise estimates of the standard errors. We would not characterize the OLS estimates of the standard errors as biased. Further, as we stated on p. 32 of the PSE report, the coefficients themselves (which form the equation used to calculate the benchmarks) remain unbiased with or without the autocorrelation correction. PSE corrected for autocorrelation in our study using the Driscoll-Kraay method as discussed in p. 32 and 33 of our report.

b) Confirmed. PSE used the command's default for the consideration of the maximum lag order of autocorrelation. The default lag equation is m(T)=floor[4(T/100)2/9].

Witness: Steve Fenrick

OEB INTERROGATORY #15

Reference:
A-04-01-01, H-01-02 p. 3

Interrogatory:
On page 23 of its report, PSE stated:

PSE used a definition of "cost" for Hydro One that allowed us to achieve comparability with the definition used for the U.S. sample. The cost of transmission services purchased by U.S. utilities from other utilities is removed from the cost definition for the U.S. sample. Subtracting "transmission of electricity by others" expenses (Uniform System of Accounts category 565, on page 321 of FERC Form 1) creates a more comparable cost definition to Hydro One and, if not subtracted, would create an unfair advantage to Hydro One, since certain U.S. utilities would have inflated expenses without commensurate output values. PSE also subtracted pensions and benefit expenses from the cost definition. Given the different healthcare structures between Canada and the U.S., this expense category could slightly inflate U.S. costs relative to Hydro One.

The transmission cost definition also includes an allocated amount of administrative and general (A&G) expenses (see page 323 of FERC Form 1).

On page 3 of Exhibit H/Tab 1/Schedule 2, Hydro One stated:

Hydro One Transmission proposes to continue to record the difference between the actual Rights Payments paid and those approved by the OEB as part of 2020-2022 Transmission Rates.

a) Are the Rights Payments tracked by the Rights Payments account reported in Transmission Account 4850 Rents? If not, please provide the account number where Rights Payments are reported and explain what rights are being addressed by this account.

b) Is the Rights Payments account still limited to rights payments made to railroads and governmental entities? What percentage of all rights payments are eligible for tracking in the Rights Payments account?

c) Please confirm that the PSE productivity and benchmarking studies included these rights payments for both the U.S. utilities and Hydro One.

Response:

a) Rights payments are tracked in specific general ledger accounts, which are then mapped to USofA 6105 Taxes Other than Income Taxes. Please see response b) below for additional information.

b) The rights payments account provides for rights payments to First Nations groups and other entities such as railways and government entities. 100% of these rights payments are eligible for tracking in the account.

c) As stated in part a) of this response, rights payments are tracked in account 6105 Taxes Other than Income Taxes. PSE excluded Taxes Other than Income Taxes from the cost definition. Therefore, Account 6105 Taxes Other than Income Taxes is not included in the cost definition for the PSE productivity and benchmarking studies.

OEB INTERROGATORY #16

<u>Reference:</u>
TSP-01-01 p. 22-23 & 28

<u>Interrogatory:</u>
At the first reference above, Hydro One stated the following:

The large industrial customers that are directly connected to Hydro One's transmission system are a critical part of Ontario's economy and, together, accounted for 1,785 MW of electricity demand in 2017, with an estimated 4% direct contribution to Ontario's GDP and a 28% contribution to Ontario's industrial GDP. These include, for instance, customer facilities for steel production, auto manufacturing, pulp and paper, chemical processing and mining. Typically, reliability and power quality for these large industrial customers are significant factors for their decisions to locate in and remain located in Ontario. Transmission outages or power quality issues can cause significant and costly interruptions to industrial processes and customer equipment, which in turn can affect company safety, performance, and employment. Hydro One developed a plan that brings reliability and power quality to these customers and which supports their businesses and Ontario's economy. These customers are sophisticated and well aware of the trade-offs between cost and reliability/power quality risk.

At the second reference above, Hydro One stated the following:

The key outcomes that Hydro One seeks to achieve through implementation of the asset management process and capital expenditure plan as set out in this TSP include, but are not limited to:

- Customer Focus: power quality improvements; improve customer reliability

a) Have customers asked specifically for power quality <u>improvements</u> and <u>improved</u> customer reliability? Please provide details to demonstrate this request.

b) Do industrial customers sensitive to reliability and power quality issues pay a premium rate to recognize their demand for superior service levels, relative to the requirements of smaller, less-sensitive loads?

c) Has Hydro One been directed to trade-off its cost of service versus the level of reliability and/or power quality risks for industrial customers by an external authority, or is this an internal decision that has been made by the company?

d) Given that Hydro One transmission does not directly serve most residential, small commercial and small industrial loads, is there a risk that the HONI transmission customer engagement process is buffered from receiving direct transmission rate feedback from most end-use customers?
   i. If yes, how does Hydro One mitigate that situation?

Response:

a) In their responses to the customer engagement survey (Exhibit B-1-1, Section 1.3, Attachment 1) customers indicated preferences for both improved reliability and improved power quality.

   The most popular investment scenario selected by customers was Scenario C which increases long-term reliability: "Scenario C… maintains current investment, decreases reliability risk, <u>increases long-term reliability</u> and offers level future rate increases…" [emphasis added] (page 45).

   Power quality was also addressed in the survey responses through a number of questions and prioritizations including the following:
   - In response to the question, "How important an outcome is power quality", 71 out of 103 participants ranked power quality as a 9 or 10 out of 10 (p. 21)
   - In terms of overall customer priorities, power quality ranked fourth out of seven (p. 28)
   - In response to the question "When you are talking about transmission reliability, what does that mean to your organization?" the response "consistent/available/stable power supply" ranked first out of seven (p. 41)
   - When asked to rank reliability items in order of importance, "overall power quality" ranked second out of five. (p. 42)
   - In responses to open-ended questions customers said:
     - Improve power quality from transformer stations (p. 66)
     - Address "power quality" (p. 67)
     - Power quality is an integral part of Reliability (p. 74)

- Note that although power quality is no[t] the bottom it is also extremely important (p. 76)
- Q: When you are talking about transmission reliability, what does that mean to your organization?
    - Reliability means minimization of incidents where power is interrupted for more than a couple seconds. It is closely related to power quality and is often used interchangeably by customers that are sensitive to power quality issues. (p. 80)
    - Zero interruptions, very low number of unplanned events such as loss of redundancy and power quality incidents (particularly voltage sags). (p. 81)
    - No unplanned outages and consistent power quality. (I.e. no impact to production). (p. 82)
    - uptime while maintaining excellent power quality (p. 83)
- Q: Is there anything else you would like to add on the topic of reliability?
    - Power quality is most important to large, power quality sensitive customers while small commercial or residential customers are most concerned with the number and duration of day-to-day interruptions. (p. 84)
    - Consistent and reasonable Power Quality is a main element any reliable electricity supply. (p. 84)

b) No.

c) Hydro One has not been directed to trade-off its cost of service versus the level of reliability and/or power quality risks for industrial customers by an external authority. When determining how and where it will invest, Hydro One's Transmission System Plan continues to strike a careful balance between: (i) asset related needs of the system arising from age, condition and environmental and regulatory compliance requirements; (ii) customer needs and preferences relating to reliability and reliability risk; (iii) regional infrastructure needs to address system constraints, enable new load growth, and facilitate access and new connections to the transmission system; and (iv) effect on customer rates.

d) No.

OEB INTERROGATORY #17

Reference:
TSP-01-01 p. 25
Figure 5

Interrogatory:

a) Under Customer Experience, what does "Foster innovation in the business to adapt to changing customer requirements and market opportunities" mean and how will success be measured?

b) Under Operational Effectiveness, what does "high level of reliability and quality" mean and how will success be measured?
   i. Are any specific costs associated with implementing this priority identified in this filing?

c) Please explain why "Invest in assets to better service customers" is included as a priority under Financial Strength.

Response:

a) “Foster innovation in the business to adapt to changing customer requirements and market opportunities” shows Hydro One’s commitment to continue to pursue new approaches to engage with customers and respond to their changing needs and preferences, including the exploration of new technology applications. Success will be measured through the overall customer satisfaction measure including on the Evolved Transmission Scorecard (Exhibit B, Tab 1, Schedule 1, Section 1.5).

b) “High level of reliability and quality” shows Hydro One’s commitment to improve reliability performance. Success will be measured through system reliability measures, including those on the Evolved Transmission Scorecard (Exhibit B, Tab 1, Schedule 1, Section 1.5).
   i. Hydro One continues to invest in major asset groups that directly affect system reliability, including transformers, breakers, conductors and protection and control systems through ongoing maintenance and system renewal, system access and system service investments. Details of investments are included in Exhibit B, Tab 1, Schedule 1, Section 3 and Exhibit F, Tab 1, Schedule 3.

c) "Invest in assets to better service customers" shows Hydro One's commitment to make proactive, timely and prudent investments to deliver service consistent with customer expectations. It is included as a priority under Financial Strength as it supports financial performance outcomes consistent with the Renewed Regulatory Framework (RRF), namely Hydro One's continuing financial viability and investing in levels that balance sustainability of the transmission system with savings from operational effectiveness.

OEB INTERROGATORY #18

Reference:

TSP-01-01 p. 26
Figure 6

Interrogatory:

a) Please explain how Figure 6 demonstrates a close alignment between Hydro One's planned transmission investments and the company's strategic priorities.

b) Under the Reliability Outcomes heading, please explain the reason for the jump in SAIDI from 2017 to 2018, given that this graph excludes Force Majeure (FM) events.

c) How is the significant projected improvement in SAIDI from 2018 to 2019 onward being achieved?

d) Under the Safety and Environment heading, please explain what "$3.5B which mitigates safety risk" means.

e) Under the Safety and Environment heading, Hydro One notes that $407M for targeted transmission line insulator programs. How does Hydro One prioritize these replacements, assuming that insulator failure presents a safety risk and given that the program spans many years?

f) Under the Reliability heading, please quantify the anticipated improvement in reliability associated with each bullet point listed.

g) As part of this filing, Hydro One has identified $681M in Productivity Savings over the forecast period.
   i. Please explain the difference between Productivity Savings (as used in Figure 6) and Progressive Productivity Savings.
   ii. Please explain how Hydro One is going to achieve these savings without impacting the overall system reliability, safety and performance.

Response:

a) Figure 6 details Hydro One’s corporate priorities under the heading “Why We Are Spending”. The “Plan Highlights” section in Figure 6 provide a summary of various

Investment Plan components that correspond with the corporate priorities by each respective category.

b) 2017 had very few significant events. Significant contributing events to 2018 results referenced in the figure are as follows:

Contribution	**Event**
26%	Extreme wind event in the province on May 4th
23%	Finch T2 transformer fire.
16%	Salt contamination issues at Gerrard TS.
9%	T31H circuit tripped due to a broken conductor while circuit T22C was out of service on planned outage.
5%	Wiltshire T2 transformer trip due to raccoon contact coincident with Wiltshire T7 transformer blindspot protection trip.
21%	Other system events.

c) Targets are established based on 10 years of data to smooth out the effects of extremely bad years and extremely good years. Proposed targets are in-line with performance expected based upon last 10 years of data and proposed investment levels. Hydro One's planned reliability improvements will be achieved through:

   a. the deployment of advanced analytics to improve asset visibility, monitoring and awareness, including
   b. investments to address performance outliers and actions to address reliability challenges, including animal abatement mitigation, pre-outage inspections, mis-operation mitigation
   c. proactive System Renewal investments which will replace assets in a deteriorated condition,
   d. selective grid hardening to improve system resilience, and
   e. System Service and System Access investments to strengthen the grid.

d) "$3.5B which mitigates safety risk" stated in Figure 6 refers to Capital and OM&A investment spend within the plan that, through the risk assessment process, provided risk mitigation on the safety risk factor.

e) Hydro One prioritizes insulator replacements based on location and system impact; for example those insulators in publically accessible, highly trafficked areas and those on critical circuits, whose failure may impact customer reliability, may be prioritized first in the context of a multi-year program.

f) $3.2B at 163 Tx stations; replacement of 117 transformers at 54 stations
   - Expected improvement of approximately 18% over baseline risk for reliability over test period.

   $252M in Tx Cyber Security
   - The work here addresses high consequence threats, much of which is NERC mandated.

   Growing Tx lines refurbishment program ($1.1B) to replace end of life lines
   - Expected improvement of approximately 0.3% over baseline risk for reliability over test period.

   Address Tx worst performing circuits impacting ~84 delivery points
   - Worst performing circuits projects are executed within "Growing Tx lines refurbishment program ($1.1B) to replace end of life lines"

   Build new Integrated System Operating Centre
   - Project meets future operating demands. Ability to operate the grid effectively and efficiently can reduce the duration of system outages.

g)
   i. Progressive Productivity is essentially a stretch target that Hydro One has committed to as part of this application. Historically, Hydro One's productivity targets were forecasted by each initiative from the bottom up. For this plan, Hydro One has embedded further defined and undefined progressive productivity target reductions on top of the specific initiatives, without reducing work volume, over the plan period. A specific initiative must be established and approved before any credit is given to achieving savings against a progressive target. Hydro One is working to establish defined initiatives to achieve the total progressive productivity commitment.
   ii. Safety, Reliability and Performance of the system will not be negatively impacted by achieving productivity savings. As noted in part i) above, Hydro One will look to achieve these savings without reductions in work volume and does not consider 'scope reductions' for tracking as an initiative. Hydro One's productivity program is further described in TSP Section 1.6.

Please refer to Exhibit I, Tab 01, Schedule OEB-002 part d) for the specific steps Hydro One is taking to identify new Progressive Initiatives.

OEB INTERROGATORY #19

<u>Reference:</u>
TSP-01-01 p. 41-42 & 45

<u>Interrogatory:</u>
At the first reference above, Hydro One stated the following:

For high-value assets, such as transformers, Hydro One's subject matter experts perform a thorough analysis and advise on issues such as equipment obsolescence, manufacturer support and conduct "repair vs. replace" evaluations. All transformer replacements require review by subject matter experts who prepare Transformer Assessment Reports that are used to validate investment decisions.

At the second reference above, Hydro One stated the following:

In summary, the investment planning process consists of the following steps:

1. <u>Investment Planning Context</u>: Hydro One draws on multiple sources of input in the development and prioritization and optimization of the investment plan consistent with Hydro One's Strategic Business Objectives and the OEB's RRF. The investment plan is guided by: (i) strategic vision, (ii) planning and other relevant economic assumptions, (iii) customer engagement feedback, (iv) delivery of key outcomes, and (v) overall assessment of the needs of Hydro One's assets, customers and other stakeholders;

a) How are the resulting projects prioritized if more projects are identified than can be completed in one year or within the planning period?

b) How is the total overall capital spending envelope determined and optimized?

c) Who sets the overall spending envelope and what parameters are used in the decision?

d) Is "Investment Planning Context" the step where overall spending envelopes are determined? If not, where does that occur?

e) How is spending optimally allocated between investment categories?

f) Are budget envelopes set independently of the asset management process?
   a. Please provide detailed explanations and specific examples of how “repair vs. replace” evaluations are conducted for different asset classes, including the parameters used in the evaluations and how decisions were made based on results of the evaluations.
   b. Please provide a continuity table showing transformer replacement expenditures across the historical, bridge and forecast years. If appropriate, the table may be categorized by transformer size and/or functionality.

Response:

a) Investments are assessed based on the operational risk that they are expected to mitigate. The results of the risk assessment are translated into risk scores which are used to prioritize and optimize the investments.

   After the initial prioritization exercise where Hydro One identifies all investments that meet the criteria identified in Exhibit B-1-1 TSP Section 2.1 (risk and other considerations), Hydro One undertakes two reviews which may result in projects or programs being removed from the plan. First, Hydro One holds challenge sessions to: (i) review an integrated portfolio, (ii) evaluate and confirm non-risk parameters (e.g. strategic, productivity investments), (iii) assess and debate investments on the margin of the funding decision, and (iv) make trade-off decisions based on facts.

   Second, as part of the Enterprise Engagement phase of the process Hydro One reviews its ability to execute the plan with the resources available to it. The final plan considers the total operation risk mitigated and further considers customer needs and preferences, asset and system needs and customer rate impacts.

   Further information may be found at Exhibit B-1-1 TSP Section 2.1

b) The initial allocation is the expenditure level included in the prior year’s plan, adjusted for efficiency gains and new strategic directions. The overall investment envelope and year-over-year pacing of investments is also informed by the feedback received through the customer engagement process. The plan is developed further, and then reviewed and approved by the Executive Leadership Team and the Board of Directors as per Exhibit B-1-1 TSP Section 2.1.8.

In this rate application, the majority of customers selected Scenario C which included a rate increase of 5.1%/year (excluding load) to improve long term reliability. Hydro One will achieve these outcomes for a lower rate increase of 4.6% / year (excluding load) from 2019-2022 which includes the OEB approved 2019 inflationary rate filing.

c) Please refer to b).

d) Yes, the initial allocations are defined during the "Investment Planning Context" step of the Investment Planning Process.

e) Hydro One's process for determining and optimizing the overall capital spending envelope is described in detail in Exhibit B-1-1 TSP Section 2.1.2 and Section 2.1.5.

f) No, the initial allocations are defined during the Investment Planning Process per Exhibit B-1-1 TSP Section 2.1.2.

   a. Please refer to Table below from Exhibit B-1-1 TSP Section 2.3 Table 1. For an example of a power transformer assessment please see Attachment 1.

Table 1 - Asset Strategy Summary

Section	Component	Asset Strategy
2.3.1.1	Transformers	Hydro One proactively inspects and monitors the transformer fleet to manage maintenance, monitor deterioration, remediate deficiencies and assess condition to determine the need for asset refurbishment or replacement on an individual basis. Asset assessment is based on risks inferred from demographics, condition, environmental settings, utilization, costs comparison between repair and replacement, and other lifecycle considerations.
2.3.1.2	Breakers	Hydro One performs routine maintenance and replaces breakers that are obsolete, pose safety risks, operate at or above their nameplate rating, exhibit unacceptable level of reliability performance, or have a poor environmental footprint in order to proactively address and prevent failure modes that could lead to outages.

Section	Component	Asset Strategy
2.3.1.3	Protection	Hydro One strives to maintain system reliability by ensuring the correct protective operation is initiated to isolate a faulted asset from the system. Hydro One performs preventive and corrective maintenance to ensure acceptable performance, maintain compliance, monitor deterioration and remediate deficiencies whenever technically and economically feasible.
2.3.1.4	Automation	Hydro One strives to ensure reliable functionality between its Control Centre and transmission assets by managing legacy obsolescence through timely replacement. As legacy automation equipment is replaced, it increases the standardization of asset and reduces corrective maintenance costs.
2.3.1.5	Power System Telecom	To ensure robust and reliable telecommunications for the protection, control and operation of the transmission system, Hydro One maintains and replaces power system telecom assets that pose a risk to reliability, safety or the environment.
2.3.1.6	Other Station Assets	Hydro One proactively manages assets through inspections and routine maintenance and monitors the fleet's condition to ensure compliance with regulatory bodies such as NERC, NPCC and the Ministry of Environment, Conservation and Parks. Repair vs. replacement assessments are done on an individual basis and are based on the risks that might arise from a demographic, condition, environmental, utilization, economic, and customer perspective. Such assessment balances the asset needs and risks as well as costs of the overall fleet.
2.3.2.1	Overhead Conductor	Hydro One manages the conductor population in a manner that maintains reliability and limits safety risk to acceptable levels. When a conductor, based on its condition as confirmed by testing, has been determined to have reached end of life, replacement is the only solution.
2.3.2.2	Underground Cables	Hydro One performs rigorous condition assessment and maintenance to maximize cable service life and replacing cables at end of life (EOL) where maintenance (repair) is no longer practical.
2.3.2.3	Steel Structures	Hydro One manages the fleet through a combination of planned structure replacements, component refurbishments and tower coating in order to maintain the reliability of the system and decrease the lifecycle costs.

Section	Component	Asset Strategy
2.3.2.3	Wood Pole Structures	Hydro One proactively replaces wood poles that are in poor condition, so as to reduce failures that impact customer reliability and safety, and to minimize emergency response activities. Hydro One uses a condition-based asset management strategy to sustain its wood pole fleet. Hydro One uses age of the wood pole as a criterion to identify the candidates for further assessment.
2.3.2.4	Insulators	Hydro One's primary focus is on the replacement of defective porcelain insulators that pose a high-risk to public safety, and end of life polymer insulators.
2.3.2.5	Rights of Way ("ROW")	Hydro One performs vegetation management on a cyclical basis. This asset strategy ensures all ROWs are regularly cleared to respect the applicable design width and to only contain compatible vegetation
2.3.2.6	Shieldwire	The asset strategy for shieldwire is to maintain system reliability and public and employee safety by replacing all shieldwire assessed to be at the end of useful service life.
2.3.2.7	Other Line Components	The asset strategy for other line components is to perform preventive maintenance and condition assessments along overhead transmission lines to identify defective equipment and components prior to failure. Hydro One executes corrective and demand maintenance to repair defective components, including end-of-life U-bolt and other hardware components. This strategy minimizes impact to customers, system reliability and public safety.
2.3.3.1	Facilities and Real Estate	Hydro One maintains facilities that are required for its operations by conducting planned maintenance of key facility systems and infrastructure. Hydro One undertakes regular inspections to identify any issues and undertake corrective maintenance where required. Hydro One conducts annual assessments to confirm facility requirements and, as necessary, complete renovations, additions, or replacements for new requirements and/or end of life condition.

Section	Component	Asset Strategy
2.3.3.2	Transport and Work Equipment (Fleet)	Hydro One strives to provide reliable equipment to employees so as to ensure the delivery of safe and economical services. Fleet Management Services and the Transmission and Stations line of business (“LOB”) complete a yearly review of all fleet and equipment that have met replacement factors against future work programs and staff needs.
2.3.3.3	Information Technology	Hydro One’s strategy is to adhere to the IT industry standard practice. It includes managing hardware assets through a life cycle program ensuring vendor support is available and decreasing the likelihood of failure. Investment decisions are based on software life cycles, vendor schedules, reliability requirements, customer requirements, and experience with similar equipment. Hydro One replaces or upgrades applications where required to ensure continued vendor support and compatibility with the current IT environment. The primary goal is to minimize business interruptions. Investment decisions are based on return on investments calculations which reflect savings and constraints of software life cycles, vendor schedules and, reliability requirements.

b. Please refer to Interrogatory I-7-SEC-36.

Bridgman T13

Transformer Assessment

Keywords: Bridgman, T13, Transformer, Transmission, Station, Assessment

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Dec 2016	0	Initial draft

APPROVAL SIGNATURES

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1. EXECUTIVE SUMMARY

- Built in 1956 and in-serviced 1957, Bridgman T13 is a 40/53/67 MVA, 110-14.2-14.2kV, 3 phase dual secondary step down transformer with 2 on load tap changers.
- The T13 Transformer at Bridgman TS has been reviewed and assessed based on: 1) Demographics, 2) Equipment condition, 3) Potential or existing environmental/HSE hazards, 4) Loading and 5) Economics.
- The assessment concluded that T13 showed signs of insulation degradation.
- T13 has heavy oil leaks from the top of the unit and requires frequent top up/repair.
- Loading on T13 is stable and well below overload limits in general.
- NPV analysis indicated minimal difference between Repair vs Replacement option starting 2017 (60 year-old), with the replacement option becoming increasing economical thereafter.
- Recommend for replacement within the next 5 years to mitigate reliability risk, environmental risk and lower future OM&A cost.

2. Equipment Summary

Built in 1956 and in-serviced 1957 by Canadian General Electric (CGE), Bridgman T13 is a 40/53/67 MVA, 110-14.2-14.2kV, 3 phase step down transformer with 2 on load tap changers (Model: LR83)

3. Demographics

T13 was in-serviced 1957 (59 years old). A total of 103 similar units are currently in service as of Dec 2015.

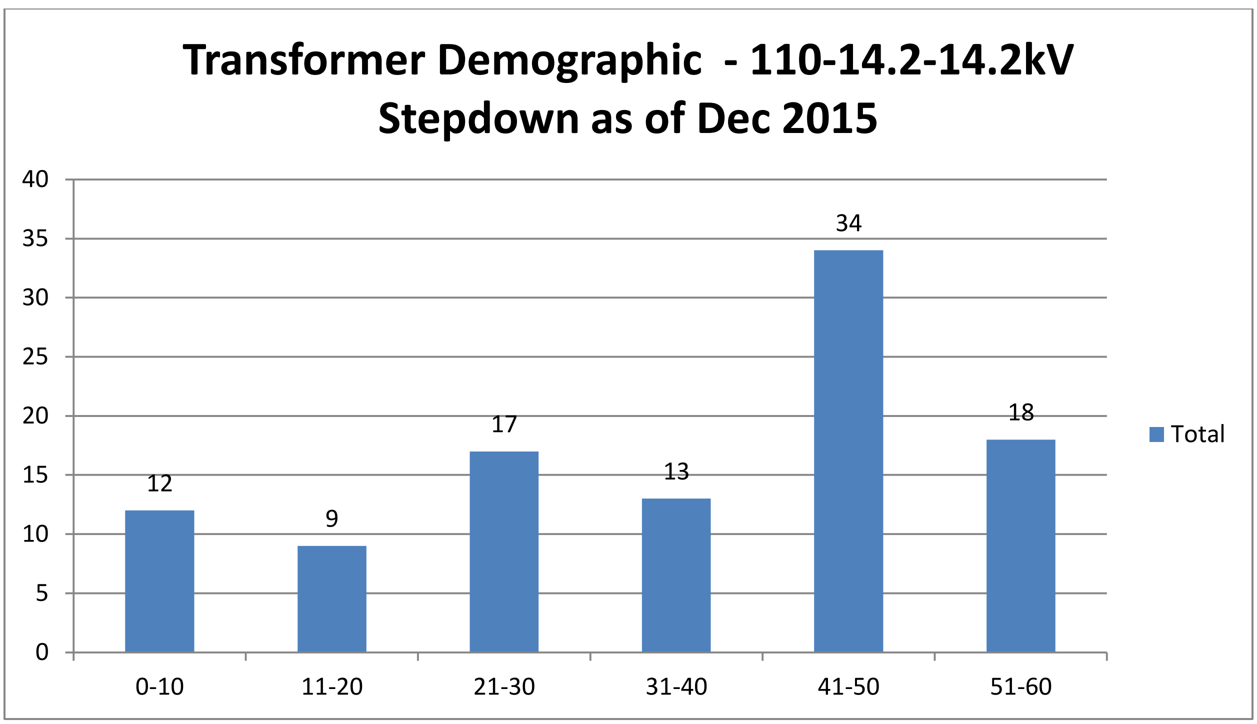


Chart 1: Transformer Demographic - 110-14.2-14.2 kV Step down Transformer as of Dec 2015

4. Equipment Condition

Equipment condition is examined based on: 1) Dissolved Gas Analysis (DGA) and 2) Preventive Maintenance Result, Trouble Calls and Deficiency Report;

4.1 Oil analysis Data

DGA results show that T13 has shown signs of insulation/paper deterioration based on increasing CO_2 and Furan. Ethylene (C_2H_4) present but has been stable.

T13's oil colour is poor and oil's dielectric strength is consistently lower than threshold. Moisture content is at or near threshold value. Power factor ratings are marginal. Overall, oil sample results suggested that T13's oil quality is marginal.

Note : Bridgman T13 has multiple oil top ups . Oil sample result may be distorted.

Date	C2H2	C2H4	C2H6	CH4	CO	CO2	H2	N2	O2	Tol Vol of Gas(%)
06/11/2011	0	17	0.42	0.265	431	3270	3.515	68300	29500	10.13
05/25/2012	0	22	0	0	501	3290	0	66200	26100	9.58
01/07/2013	0	24	0	0	434	3650	10	64400	24800	9.29
05/24/2014	0	20	0	0	371	3030	10	74200	29100	10.63
09/11/2014	0	23	0	0	480	3570	15	65400	25000	9.41
11/07/2014	0	8	0	0	463	3610	15	65600	24900	9.41
01/23/2015	0	20	0	0	442	3790	15	65600	26400	9.58
11/21/2015	0	18	0	0	520	4060	20	63300	22400	8.98

Table 1: DGA results for T13 from previous years. Quantities that are beyond warning limits are underlined and highlighted in red.

Date	Acidity	Colour	Furan	IFT	kV (ASTM D1816)	kV (ASTM D877)	Moisture	pf @ 25 °C
06/11/2011	0.03	2	228	27.2	34	39	20	0.26
05/25/2012	0.04	2	235	26.5	27	26	21	0.23
01/07/2013	0.08	4	261	27	53	49	7	0.11
05/24/2014	0.04	2	295	27.8	31	47	16	0.14
09/11/2014	0.04	2	305	27.6	16	24	20	0.17
11/07/2014	0.04	2	325	27.6	31	44	14	0.13
01/23/2015	0.04	2	273	27.6	40	37	13	0.17
11/21/2015	0.03	3	320	27.3	28	35	18	0.12

Table 2:Bridgman T13 Oil quality from previous years. Quantities that are beyond warning limits are underlined and highlighted in red.

4.2 Maintenance History, Trouble Calls and Deficiency Report

Standard power transformer maintenance packages are applied on Bridgman T13 per Hydro One Work Standard Document SM-54-007 (main tank) and SM-54-033 (ULTC) respectively.

Preventive Maintenance schedule and results are summarized in Table below.

Maintenance Item	2011	2012	2013	2014	2015	2016	2017
TF-GENERAL-DBT (8 year interval)							x
TF-GENERAL-D1 (4 year interval)					CR01		x
TF-GENERAL-D2 (8 year interval)							x
TF-GENERAL-GOT (Annual)	CR01	CR01	CR01	CR02	CR01	CR01	x
UT-CGE-LR59/65/68/83-SI (X) (4 year interval)					CR01		
UT-CGE-LR59/65/68/83-UTOA (X) (2 year interval)	CR02			CR03	CR01		x
UT-CGE-LR59/65/68/83-SI (Y) (4 year interval)					CR01		
UT-CGE-LR59/65/68/83-UTOA (Y) (2 year interval)	CR03			CR03	CR01		x

Table 3: Preventive maintenance summary of T13 and future schedule (marked by x)

A list of all Preventive maintenance results is appended in Appendix I. Overall, it is concluded that preventive maintenance results are satisfactory. In 2011 and 2014, T13's tap changer oil samples are rated unacceptable (CR03) with suspected moisture ingress. Subsequent resamples yielded acceptable result. [Ref notification : 10734999, 13420143, 13420145]

Equipment Obsolescence

T13 is a CGE Transformer that uses a CGE LR 83 tap changer, which are supported by GE Energy Services. No obsolescence issue foreseen at this stage.

Trouble calls/deficiency report

Lists of trouble calls/deficiency report are reviewed and appended in Appendix II. It is concluded that defects found are mostly oil leak related. Highlights include:

1. T13 has repeated oil leaks observed from the top of the transformer and has needed multiple oil top ups. The main tank Qualitrol and gasket were replaced. [Ref. notifications: 10312601, 10865627, 10867109, 14418043, 14575672]
2. Repeated cooling deficiencies observed including defective fans and blown up fuses which were either required replacement or troubleshooting. [Ref. notifications:10184790, 10493615, 13953022]
3. T13 X blue and white phase pad connections on the inter bus connection top of structure showed hotspots through thermo-vision . The ocnnection were taken apart, cleaned, greased and then installed back. [Ref. notification: 10508319, 10508320]

Oil top up data in SAP:

Year	Vol. of Oil (L)	Incurred Cost
2009	1000	$ 3,367.85
2016	1000	$ 594.26
Total	**2000**	**$ 3,962.11**

5 Potential Environmental Risk/HSE

5.1 Spill Risk Assessment

Bridgman TS is ranked as moderate-risk for spill containment (4 of 256) stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [1]. Bridgman T13 is equipped with containment that meets Hydro One standards, but in a poor condition.

5.2 PCB content

Table below summarized the latest PCB content detected in various part of the equipment. Hydro One is obligated to remove or retrofit equipment with PCB contamination >50ppm per Environment Canada regulation by 2025.

Equipment	Description	Date	PCB	Lab Reference
1188441	TF: Stepdn - 66.7MVA 110-14.2-14.2kV	11/21/2015	7	M299971A
1222212	(X) TF: ULTC - 13 kV Div/Sel	11/21/2015	1	M299972A
1222214	(Y) TF: ULTC - 13 kV Div/Sel	11/21/2015	2	M299973A
1228187	(Y3) - BUSHING: 15 kV	n/a	[unknown]	
1228189	(Y2) - BUSHING: 15 kV	n/a	[unknown]	
1228191	(Y1) - BUSHING: 15 kV	n/a	[unknown]	
1228193	(X3) - BUSHING: 15 kV	n/a	[unknown]	
1228195	(X2) - BUSHING: 15 kV	n/a	[unknown]	
1228197	(X1) - BUSHING: 15 kV	n/a	[unknown]	
1228199	(H0) - BUSHING: 15 kV	n/a	[unknown]	
1228201	(H2) - BUSHING: 115 kV	06/28/2011	10	#B191011
1228203	(H1) - BUSHING: 115 kV	06/28/2011	11	#B191011
1228205	(H3) – Bushhing: 115 kV	06/28/2011	11	#B191011

Table 4: PCB Content for various equipment

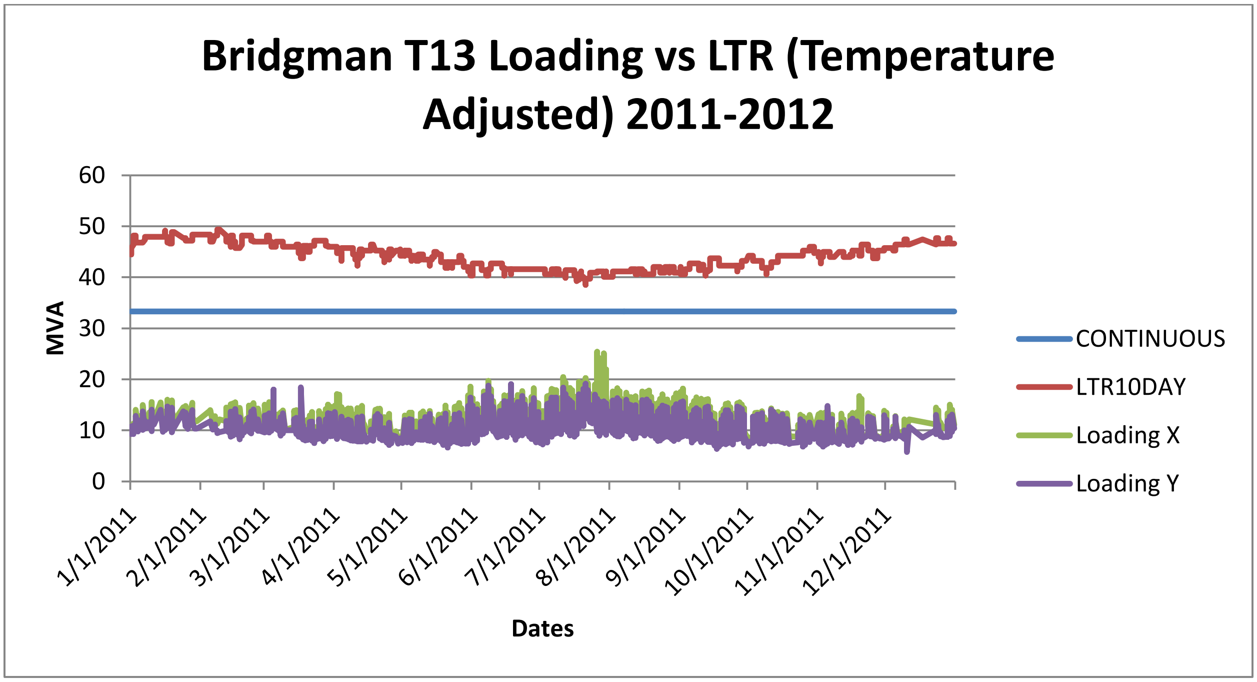
6 Equipment Loading

Bridgman T13 is 40/53/67 MVA dual secondary winding transformer with summer and winter Limited Time Rating (LTR) stated below:

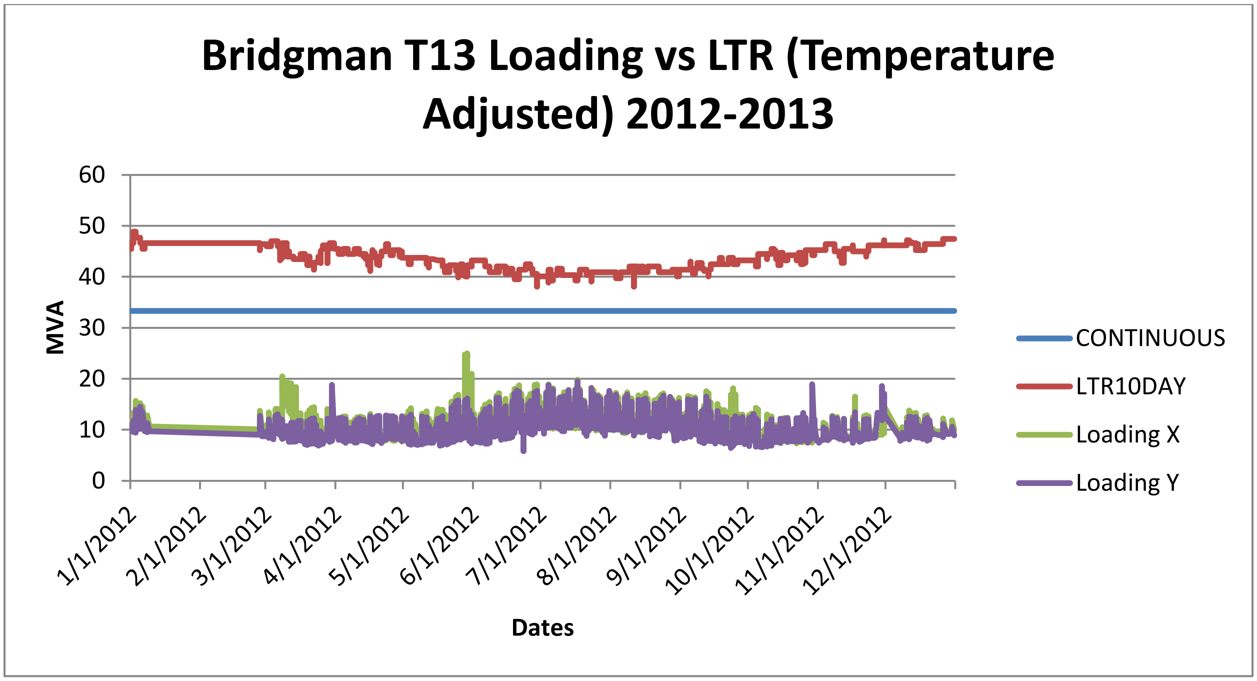
T13X and T13Y:

Summer 10d LTR (31 ºC)	Winter 10d LTR (5ºC)
40MVA	46MVA

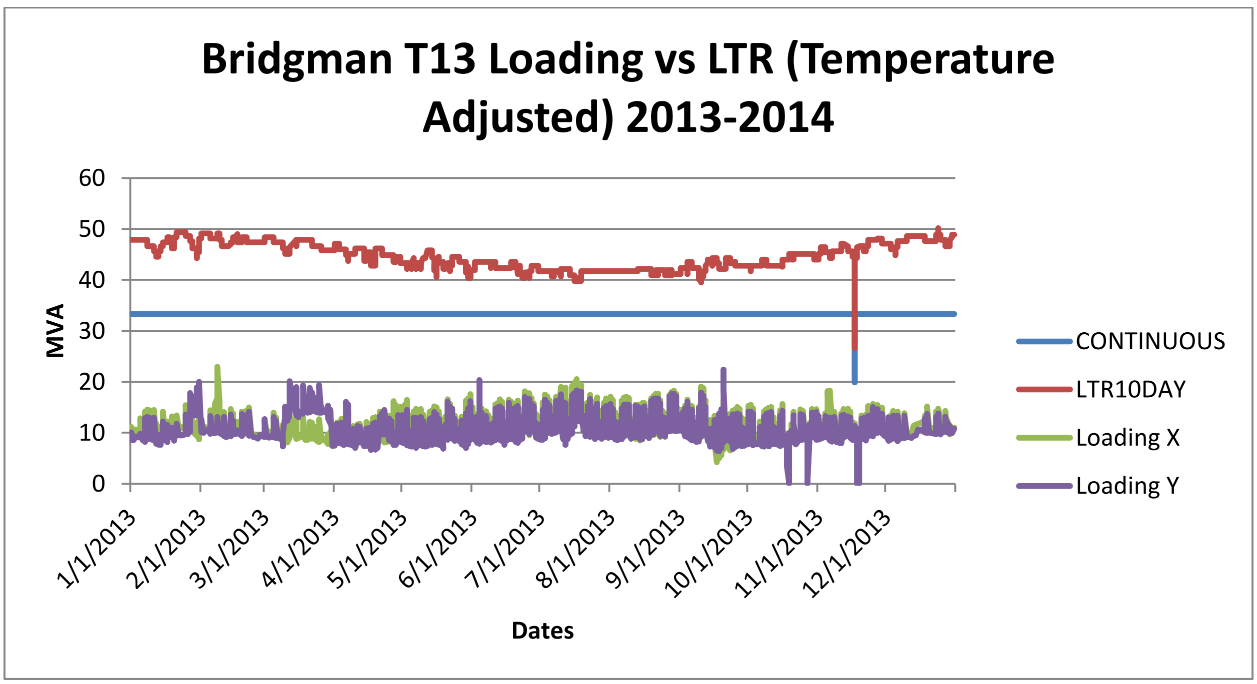
Bridgman T13's loading was reviewed with respect to its temperature adjusted LTR from 2011 -2015. It is observed T13's loading is positioned well below various loading limits. Loading surges were observed occasionally but within acceptable limits.



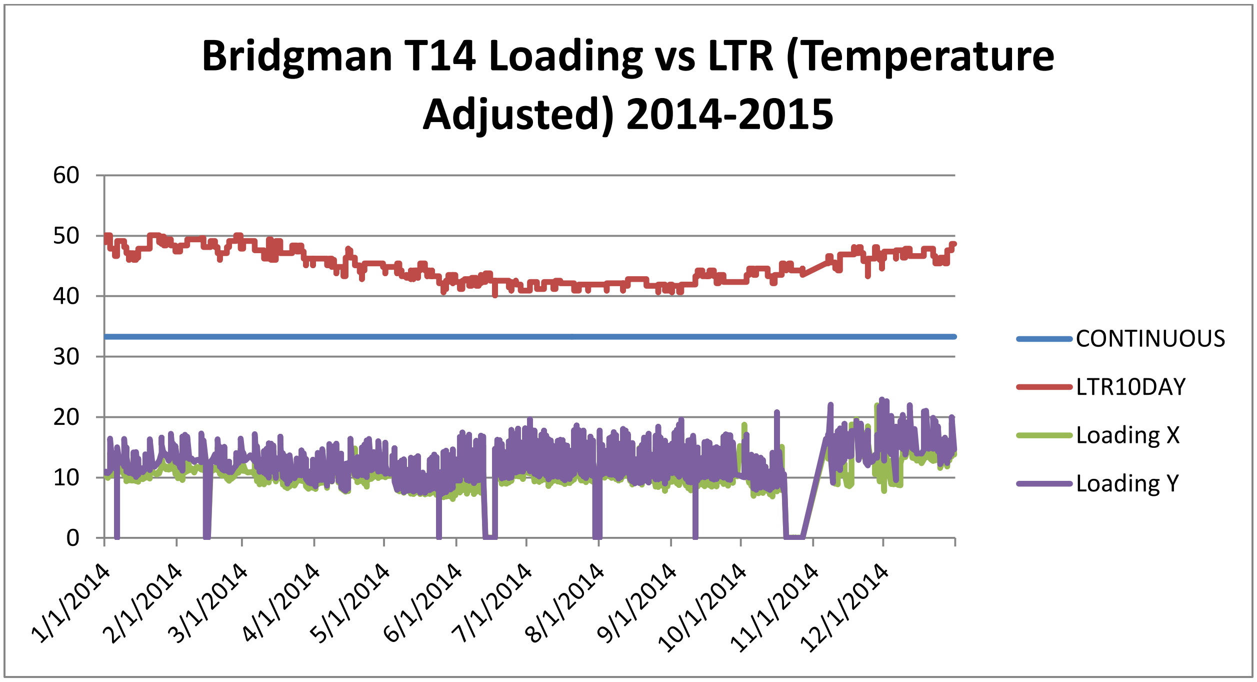
Graph 1: Bridgman T13 Loading vs LTR (Temperature Adjusted) 2011-2012



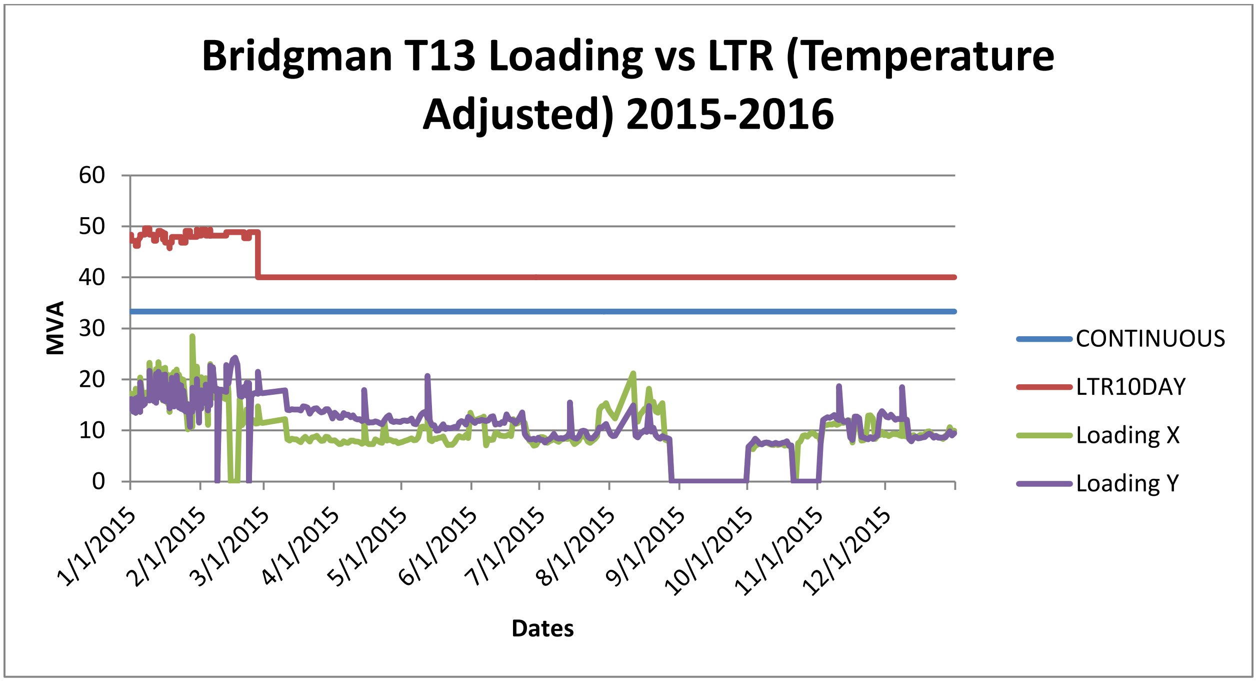
Graph 2: Bridgman T13 Loading vs LTR (Temperature Adjusted) 2012-2013



Graph 3: Bridgman T13 Loading vs LTR (Temperature Adjusted) 2013-2014



Graph 4: Bridgman T13 Loading vs LTR (Temperature Adjusted) 2014-2015



Graph 5: Bridgman T13 Loading vs LTR (Temperature Adjusted) 2015 -2016

7 Economics

7.1 Recorded OM&A Spending.

Table 4 summarized OM&A spending incurred on Bridgman T13 since SAP inception in 2008. It is concluded that Preventive maintenance spending went as planned.

T13 has incurred higher corrective cost in 2009 due to oil leak inspections and repairs. [Ref. Notifications: 10312601]

Row Labels	CORR	EMER	OPER	PREV	UPGR	Grand Total
2008				$3,521.00		$3,521.00
2009	$15,805.93	$4,208.60		$5,512.75		$25,527.28
2010	$1,117.32	$1,864.04		$8,476.51	$74.37	$11,532.24
2011		$506.34		$2,151.04		$2,657.38
2012	$3,367.85	$2,193.51		$505.98		$6,067.34
2013		$3,737.87				$3,737.87
2014	$5,481.16	$8,198.24		$22,563.27		$36,242.67
2015	$8,959.68	$6,135.65		$3,871.48		$18,966.81
2016	$3,489.86		$4,682.25			$8,172.11
Grand Total	**$38,221.80**	**$26,844.25**	**$4,682.25**	**$46,602.03**	**$74.37**	**$116,424.70**

Table 5: Historical OM&A spending on T13

PREV Maintenance Activity	Average Actual Cost (2013 - 2015)	Applicable to unit under assessment
TAP CHANGER OIL SAMPLES	$ 370.51	✓
TAP CHANGER SI	$ 7019.4	✓
TRANSFORMER DBT --General	$ 5,660.90	✓
TRANSFORMER D1 --General	$ 3,862.40	✓
TRANSFORMER D2 --General	$ 3,517.07	✓
TRANSFORMER OIL SAMPLES --General	$ 300.57	✓

Table 6: Unit cost of various Preventative Maintenance Activities. Based on actual unit cost from 2013-2015

7.2 Net Present Value Analysis

This section evaluates the cost benefit for various asset management options (Status Quo Maintain, repair, replacement) of T13 with Net Present Value Analysis (NPV).

- Status Quo Maintain: Perform routine maintenance to keep the unit in service. Replace at economic end of life (2021). Continue to maintain new unit to end of study period (2081).
- Repair/Refurbish: Perform major repair/refurbishment in the year of interest (2017), then maintain as normal and replace the unit at economic end of life (2021). Continue to maintain new unit to end of study period (2081).
- Replace: Advance the replacement to the year of interest (2017) instead of performing a refurbishment. Continue to maintain new unit to end of study period (2081).

The study makes the following assumptions:

- Study period : 64 years[1]
- T13 will undergo refurbishment/ repair at 60 year old (2017), at approx. CAD$583.8k[2].
- Replacement cost is assumed to be CAD$5.8M[3] for a unit that matches purchasing standard S115-106
- The new unit will benefit from lower OM&A cost because it will be equipped with vacuum tap changer. Estimated interval for internal inspection is lengthened to 12 years. New unit will utilize Buchholz relay and eliminate D2 maintenance task.
- Inflation: 2%. [2]
- Cost of Capital: 5.78% [2]
- Corporate Tax rate : 26.5% [2]
- CCA rate for Transmission Asset : 8% [2]
- Disposal Value : $0
- Average corrective cost of CAD$8K per year. (Total : CAD $32K)

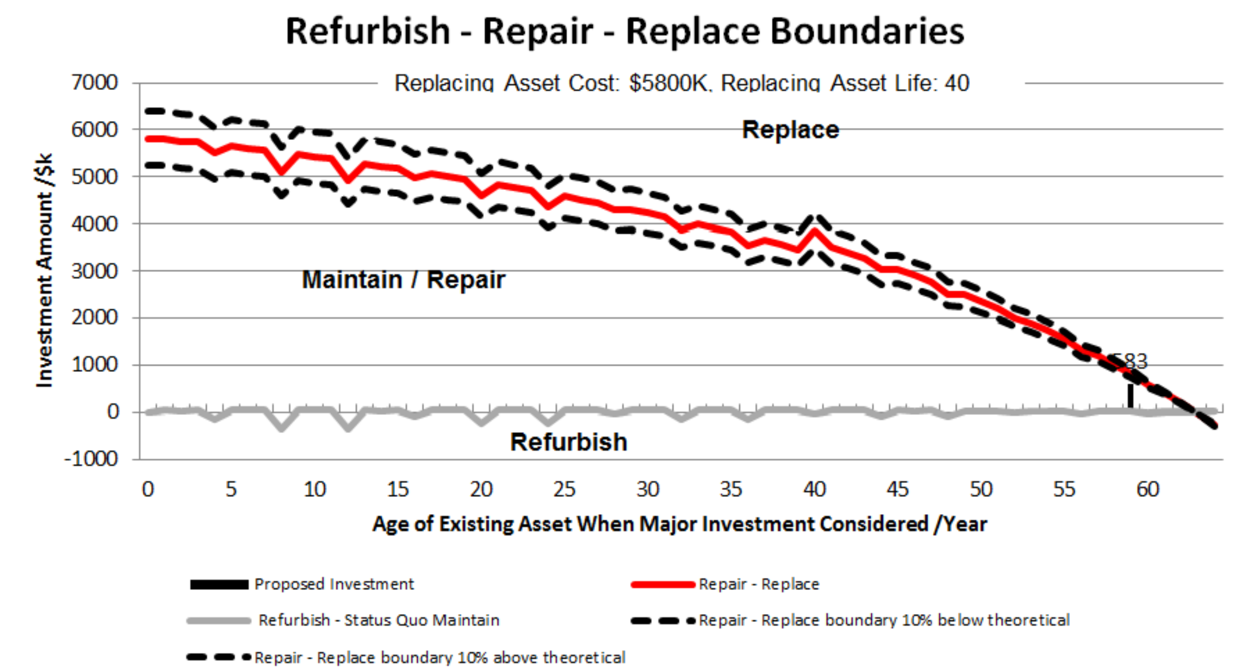
NPV of 3 options (Status Quo Maintain, Repair and Replace) were evaluated under the aforementioned assumptions. In general, NPV calculation has preferred the option to maintain status quo and wait for replacement as it has the lowest present value.

Should a repair becomes necessary, the maximum economically viable budget to repair/refurbish the unit is CAD $583.8K - CAD $39.88K = CAD $543.92K. Therefore, the model suggests that it will be more economical to replace instead of to repair/refurbish the unit when T13 reaches 60 years old and onwards.

Result Summary	Status Quo Maintain	Major Investment Maintain/Repair	Replace	Preferred Option
With CCA tax savings				
PV of Options, $k, with terminal value	5262.46	5809.02	5769.14	
PV of Options, $k, terminal value = 0	5377.25	5923.81	5993.20	
Investment Decision		NPV, $k		
Status Quo Maintain - Refurbish		-546.56		Maintain
Major Investment (Repair/Refurbish) - Replace		39.88		Further Review
Repair - Replace boundary			543.92	
Repair - Replace boundary, upper bound			598.31	
Repair - Replace boundary, lower bound			489.53	

Table 7: Present Value comparison for different sustainment options.

[1] Study period lengthen to 64 years to accommodate the fact that the unit is already 60 years old. Normal Study period is 40 years
[2] $583.8 K is the 2010 – 2015 recorded average cost to refurbish transformer under AR 18335 (Transformer Oil Leak Reduction)
[3] Based on 2015 March, Average I/S Cost for Power Transformers in 115kV class.



Graph 6: Visual Representation of NPV analysis

8 Conclusion

The demographics data, condition data, environmental/HSE hazards, equipment loading and economics related to Bridgman T13 have been reviewed. T13's oil data have shown signs of paper insulation deterioration. T13's overall maintenance history recorded multiple oil leaks on the transformer which has required multiple oil top ups in the past. A review of T13's loading has revealed that it is lightly loaded with respect to its various loading limits from 2011-2015. An NPV analysis has been performed and has concluded that there is minimal difference between repair vs replace starting 2017. In conclusion, a replacement of the unit within 5 years from 2016 would be considered prudent and beneficial as it can lower reliability risk, environmental risk and lower future OM&A cost.

9 Reference

[1] Conestoga-Rogers & Associates. (2011). Hydro One Station Spill Risk Model. SIP-EnvMgmt-0100, Mississauga.

[2] Department of Economics and Load Forecasting, Hydro One Networks Inc. (2015), Hydro One Financial Evaluation Model, Toronto.

APPENDIX 1 – PREVENTIVE MAINTENANCE RESULT

Notification	Notifictn type	Coding	Functional Loc.	Notif.date	Description
10022811	PR		N-TS-BRIDGMANTS-TF-T13	07/04/2008	UT-CGE/CWC/EE/LR&U-SI
10022810	PR		N-TS-BRIDGMANTS-TF-T13	07/04/2008	UT-CGE/CWC/EE/LR&U-D1
10022812	PR		N-TS-BRIDGMANTS-TF-T13	07/04/2008	UT-CGE/CWC/EE/LR&U-D1
10022813	PR		N-TS-BRIDGMANTS-TF-T13	07/04/2008	UT-CGE/CWC/EE/LR&U-SI
10210214	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/31/2008	TF-GENERAL-GOT
10237914	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237886	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237887	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237888	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237839	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237840	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237841	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237842	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237843	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237844	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10237845	PR	CR01	N-TS-BRIDGMANTS-TF-T13	12/22/2008	STN 'B' PWR EQ INSP-SVI
10253439	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/17/2009	UT-CGE/CWC/EE/LR&U-UTOA
10253440	PR	CR03	N-TS-BRIDGMANTS-TF-T13	01/17/2009	UT-CGE/CWC/EE/LR&U-UTOA
10298170	PR	CR01	N-TS-BRIDGMANTS-TF-T13	05/01/2009	TF-GENERAL-D1
10298171	PR	CR01	N-TS-BRIDGMANTS-TF-T13	05/01/2009	TF-GENERAL-DBT
10298172	PR	CR01	N-TS-BRIDGMANTS-TF-T13	05/01/2009	TF-GENERAL-M1
10314334	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314306	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314307	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314308	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314259	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314260	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314261	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI

10314262	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314263	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314264	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10314265	PR	CR01	N-TS-BRIDGMANTS-TF-T13	06/15/2009	STN 'B' PWR EQ INSP-SVI
10346765	PR	CR01	N-TS-BRIDGMANTS-TF-T13	08/18/2009	UT-CGE/CWC/EE/LR&U-UTOA
10358553	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/21/2009	STN 'B' PWR EQ INSP-SVI
10413002	PR		N-TS-BRIDGMANTS-TF-T13	12/17/2009	UT-CGE/CWC/EE/LR&U-D1
10413024	PR		N-TS-BRIDGMANTS-TF-T13	12/17/2009	UT-CGE/CWC/EE/LR&U-D1
10432249	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/08/2010	TF-GENERAL-GOT
10480502	PR		N-TS-BRIDGMANTS-TF-T13	03/25/2010	TF-GENERAL-M1
10541991	PR	CR02	N-TS-BRIDGMANTS-TF-T13	09/21/2010	STN 'B' PWR EQ INSP-SVI FALL
10542016	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/21/2010	STN 'B' PWR EQ INSP-SVI FALL
10542017	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/21/2010	STN 'B' PWR EQ INSP-SVI FALL
10560953	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/04/2010	TF-GENERAL-GOT
10592176	PR	CR02	N-TS-BRIDGMANTS-TF-T13	10/15/2010	UT-CGE/CWC/EE/LR&U-UTOA
10592178	PR	CR03	N-TS-BRIDGMANTS-TF-T13	10/15/2010	UT-CGE/CWC/EE/LR&U-UTOA
10658785	PR		N-TS-BRIDGMANTS-TF-T13	02/12/2011	20216 2011Tx PCB Reduction Oil Sample
10669041	PR	CR01	N-TS-BRIDGMANTS-TF-T13	03/22/2011	STN 'B' PWR EQ INSP-SVI SPRING 2011
10669083	PR	CR01	N-TS-BRIDGMANTS-TF-T13	03/22/2011	STN 'B' PWR EQ INSP-SVI SPRING 2011
10669084	PR	CR01	N-TS-BRIDGMANTS-TF-T13	03/22/2011	STN 'B' PWR EQ INSP-SVI SPRING 2011
10734999	PR	CR02	N-TS-BRIDGMANTS-TF-T13	09/15/2011	UT-CGE-LR59/65/68/83-(SPECIAL) MCT
10743255	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/21/2011	STN 'B' PWR EQ INSP-SVI FALL 2011
10743296	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/21/2011	STN 'B' PWR EQ INSP-SVI FALL 2011
10743297	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/21/2011	STN 'B' PWR EQ INSP-SVI FALL 2011
10771248	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/21/2011	TF-GENERAL-GOT
10881637	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/03/2012	STN 'B' PWR EQ INSP-SVI SPR 2012
10881678	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/03/2012	STN 'B' PWR EQ INSP-SVI SPR 2012
10881679	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/03/2012	STN 'B' PWR EQ INSP-SVI SPR 2012
11794050	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/02/2012	STN 'B' PWR EQ INSP-SVI AUT 2012
11794187	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/02/2012	STN 'B' PWR EQ INSP-SVI AUT 2012
11794189	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/02/2012	STN 'B' PWR EQ INSP-SVI AUT 2012

11824359	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/13/2012	TF-GENERAL-GOT
11825643	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/13/2012	UT-CGE-LR59/65/68/83-UTOA
11825645	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/13/2012	UT-CGE-LR59/65/68/83-UTOA
11973734	PR	CR03	N-TS-BRIDGMANTS-TF-T13	11/27/2012	20216TxPCBsample2013
12059691	PR	CR01	N-TS-BRIDGMANTS-TF-T13	02/08/2013	UT-CGE-LR59/65/68/83-SI
12059692	PR	CR01	N-TS-BRIDGMANTS-TF-T13	02/08/2013	UT-CGE-LR59/65/68/83-SI
12067033	PR	CR01	N-TS-BRIDGMANTS-TF-T13	02/27/2013	TF-GENERAL-D1 2013
12190585	PR	CR01	N-TS-BRIDGMANTS-TF-T13	05/02/2013	STN 'B' PWR EQ INSP-SVI SPR 2013
12190653	PR	CR01	N-TS-BRIDGMANTS-TF-T13	05/02/2013	STN 'B' PWR EQ INSP-SVI SPR 2013
12190655	PR	CR01	N-TS-BRIDGMANTS-TF-T13	05/02/2013	STN 'B' PWR EQ INSP-SVI SPR 2013
12643129	PR	CR02	N-TS-BRIDGMANTS-TF-T13	09/26/2013	TF-GENERAL-GOT
12774192	PR	CR01	N-TS-BRIDGMANTS-TF-T13	11/14/2013	STN 'B' PWR EQ INSP-SVI FALL 2013
12774234	PR	CR01	N-TS-BRIDGMANTS-TF-T13	11/14/2013	STN 'B' PWR EQ INSP-SVI FALL 2013
12774235	PR	CR01	N-TS-BRIDGMANTS-TF-T13	11/14/2013	STN 'B' PWR EQ INSP-SVI FALL 2013
12873343	PR	CR01	N-TS-BRIDGMANTS-TF-T13	02/28/2014	PREOUTAGE INSPECTION- CAT 1 - G&S
12873342	PR		N-TS-BRIDGMANTS-TF-T13	02/28/2014	PREOUTAGE INSPECTION- CAT 2 - ELEC
12882409	PR	CR01	N-TS-BRIDGMANTS-TF-T13	03/14/2014	PREOUTAGE INSPECTION- CAT 1 - G&S
12882408	PR	CR03	N-TS-BRIDGMANTS-TF-T13	03/14/2014	PREOUTAGE INSPECTION- CAT 2 - ELEC
12941556	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/30/2014	STN 'B' PWR EQ INSP-SVI SPRING 2014
12941597	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/30/2014	STN 'B' PWR EQ INSP-SVI SPRING 2014
12941598	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/30/2014	STN 'B' PWR EQ INSP-SVI SPRING 2014
13352961	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/25/2014	TF-GENERAL-(SPECIAL)DLT-D877&D1816
13368882	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/26/2014	TF-GENERAL-GOT
13368819	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/26/2014	UT-CGE-LR59/65/68/83-UTOA
13368821	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/26/2014	UT-CGE-LR59/65/68/83-UTOA
13420143	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/27/2014	UT-CGE-(SPECIAL)MCT- XLTC-DIV
13420145	PR	CR01	N-TS-BRIDGMANTS-TF-T13	10/27/2014	UT-CGE-(SPECIAL)MCT - YLTC-DIV
13431501	PR	CR01	N-TS-BRIDGMANTS-TF-T13	11/07/2014	STN 'B' PWR EQ INSP-SVI FALL 2014
13431547	PR	CR01	N-TS-BRIDGMANTS-TF-T13	11/07/2014	STN 'B' PWR EQ INSP-SVI FALL 2014
13431549	PR	CR01	N-TS-BRIDGMANTS-TF-T13	11/07/2014	STN 'B' PWR EQ INSP-SVI FALL 2014
13606838	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015

13607152	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13607153	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606945	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606946	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606947	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606948	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606949	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606980	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606981	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606982	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606983	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
13606984	PR	CR01	N-TS-BRIDGMANTS-TF-T13	04/10/2015	STN 'B' PWR EQ INSP-SVI SPRING 2015
14041859	PR	CR01	N-TS-BRIDGMANTS-TF-T13	07/24/2015	TF-GENERAL-GOT
14409443	PR	CR01	N-TS-BRIDGMANTS-TF-T13	11/20/2015	PREOUTAGE INSPECTION- CAT 1 - ELEC
14491424	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491341	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491462	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491405	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491318	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491319	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491338	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491484	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491342	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491406	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491409	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491420	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14491485	PR	CR01	N-TS-BRIDGMANTS-TF-T13	01/05/2016	STN 'B' PWR EQ INSP-SVI FALL 2015
14527293	PR	CR03	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14527294	PR	CR03	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14527295	PR	CR03	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14527296	PR	CR03	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013

14527297	PR	CR03	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14527298	PR	CR03	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14527299	PR	CR03	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14527370	PR	CR01	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14527371	PR	CR01	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14527372	PR	CR01	N-TS-BRIDGMANTS-TF-T13	03/02/2016	20216 Tx PCB sample 2013
14896224	PR		N-TS-BRIDGMANTS-TF-T13	07/16/2016	TF-GENERAL-DBT
14924350	PR		N-TS-BRIDGMANTS-TF-T13	07/16/2016	TF-GENERAL-D2
14896221	PR		N-TS-BRIDGMANTS-TF-T13	07/16/2016	TF-GENERAL-D1
14896223	PR		N-TS-BRIDGMANTS-TF-T13	07/16/2016	TF-GENERAL-GOT
14903703	PR		N-TS-BRIDGMANTS-TF-T13	07/16/2016	UT-CGE-LR59/65/68/83-UTOA
14903704	PR		N-TS-BRIDGMANTS-TF-T13	07/16/2016	UT-CGE-LR59/65/68/83-UTOA
15121987	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122346	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122365	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122086	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122080	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122102	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122103	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122109	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122140	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122141	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122146	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122147	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016
15122182	PR	CR01	N-TS-BRIDGMANTS-TF-T13	09/27/2016	STN 'B' PWR EQ INSP-SVI FALL 2016

APPENDIX 2 – LIST OF DR AND TC NOTIFICATION

Notification	Notifictn type	Coding	Functional Loc.	Notif.date	Description
13845675	DR		N-TS-BRIDGMANTS-TF-T13	06/03/2015	AR#20241 NT31 UCL Plate Program BTU
10508320	DR		N-TS-BRIDGMANTS-TF-T13	05/25/2010	HOTSPOT
10508319	DR		N-TS-BRIDGMANTS-TF-T13	05/25/2010	HOTSPOT
12867795	DR	9900	N-TS-BRIDGMANTS-TF-T13	02/13/2014	NT31 Inspect transfrmer for oil leaks
10184790	DR	1600	N-TS-BRIDGMANTS-TF-T13	10/22/2008	Bridgman TS T13 Cooling Fan
10184789	DR	0700	N-TS-BRIDGMANTS-TF-T13	10/22/2008	Bridgman TS T13 Oil Leak
14575672	DR	0700	N-TS-BRIDGMANTS-TF-T13	04/15/2016	Bridgman T13 low oil level
10865627	DR		N-TS-BRIDGMANTS-TF-T13	02/11/2012	Bridgman T13 low oil
11643736	DR	9900	N-TS-BRIDGMANTS-TF-T13	08/28/2012	Replace Hads wiring
10138597	DR		N-TS-BRIDGMANTS-TF-T13	10/08/2008	hot connector on secondary bus of t13x
10493615	DR	1600	N-TS-BRIDGMANTS-TF-T13	04/22/2010	Bridgman TS T13 Cooling Fan
14498600	DR	9900	N-TS-BRIDGMANTS-TF-T13	01/26/2016	T13 Faulty HADs wiring.
10312601	DR	9900	N-TS-BRIDGMANTS-TF-T13	06/11/2009	Bridgman TS T13 Oil Leak
13953022	DR	1600	N-TS-BRIDGMANTS-TF-T13	07/02/2015	Bridgman T13 cooling fail
14404165	DR	0100	N-TS-BRIDGMANTS-TF-T13	11/19/2015	Bridgman T13 tapchanger indication
14418043	DR	0700	N-TS-BRIDGMANTS-TF-T13	11/24/2015	Bridgman T13 conservator low oil
10530204	TC		N-TS-BRIDGMANTS-TF-T13	07/28/2010	Sec 3 Bridgeman TS T13
11979282	TC		N-TS-BRIDGMANTS-TF-T13	11/27/2012	S3 IMD EMD RE:Bridgman T13
12023836	TC		N-TS-BRIDGMANTS-TF-T13	12/06/2012	s3 bridgeman
13056680	TC		N-TS-BRIDGMANTS-TF-T13	06/17/2014	s3 (EMD) RE: T13
10868987	TC		N-TS-BRIDGMANTS-TF-T13	02/24/2012	S3 - RE - SWITCHING ON THE T13
14315874	TC		N-TS-BRIDGMANTS-TF-T13	10/22/2015	SEC 2 - EMD - T13 SWITCHING
13042236	TC		N-TS-BRIDGMANTS-TF-T13	06/13/2014	s1 pd p&c re: t13 trip
10433094	TC		N-TS-BRIDGMANTS-TF-T13	01/10/2010	sect 3 re bridgeman-t13
14309463	TC		N-TS-BRIDGMANTS-TF-T13	10/21/2015	S3 P&C PD T13 FEEDER DIFFERENTIAL PROTE
15136308	TC		N-TS-BRIDGMANTS-TF-T13	09/30/2016	SEC3-EMD IMMEDIATE-BRIDGEMAN TS-T13
11979155	TC		N-TS-BRIDGMANTS-TF-T13	11/28/2012	S3 EMD PD SWITCHING T13

10280052	TC		N-TS-BRIDGMANTS-TF-T13	03/28/2009	S3 - Bridgeman T13 Check relaying
10306759	TC		N-TS-BRIDGMANTS-TF-T13	05/31/2009	S3 - Bridgeman TS - T13
10280050	TC		N-TS-BRIDGMANTS-TF-T13	03/28/2009	S3 - Bridgeman TS T13 Switching
10523940	TC		N-TS-BRIDGMANTS-TF-T13	07/05/2010	S3 RE: Bridgeman Switching T13
10523882	TC		N-TS-BRIDGMANTS-TF-T13	07/04/2010	S3-EMD-BRIDGEMAN TS-T13X PILOT WIRE
10813626	TC		N-TS-BRIDGMANTS-TF-T13	12/12/2011	S3 PD EMD Switching T13
10867109	TC		N-TS-BRIDGMANTS-TF-T13	02/21/2012	S3 - T13 OIL LEVEL CONCERN
10864987	TC		N-TS-BRIDGMANTS-TF-T13	02/11/2012	S3 IM EMD RE: T13 low oil
13052845	TC		N-TS-BRIDGMANTS-TF-T13	06/17/2014	S3: PNDING - EMD - ISOLATE T13 - BRIDGEM
13043259	TC		N-TS-BRIDGMANTS-TF-T13	06/13/2014	S3 IM EMD RE: T13 switching for Toronto
13190864	TC		N-TS-BRIDGMANTS-TF-T13	07/30/2014	T13 BLINDSPOT PROTECTION TRIP
13045240	TC		N-TS-BRIDGMANTS-TF-T13	06/14/2014	S3-EMD-ISOLATION T13
13042234	TC		N-TS-BRIDGMANTS-TF-T13	06/13/2014	s3 imd emd re: check t13 trip
14236608	TC		N-TS-BRIDGMANTS-TF-T13	09/29/2015	S3 EMD UNPLANNED SWITCHING T13
14309550	TC		N-TS-BRIDGMANTS-TF-T13	10/21/2015	S3^ P&C^ BRIDGEMAN TS^ RE: T13 Y WINDING
14421826	TC		N-TS-BRIDGMANTS-TF-T13	11/25/2015	S3 EMD SWITCHING T13 TRANSFORMER
14309462	TC		N-TS-BRIDGMANTS-TF-T13	10/21/2015	S3 EMD PD T13 FEEDER DIFFERENTIAL

OEB INTERROGATORY #20

Reference:
TSP-01-01 p. 43

Interrogatory:
At the above noted reference, Hydro One stated the following:

This station-focused approach addresses infrastructure that is aging and in poor condition, and integrates OM&A and capital programs across multiple disciplines. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 294 transmission stations during the cycle. This ensures that asset needs at all stations are reviewed on a recurring basis, which may or may not result in the need for investment after applying the ARA process. By developing and implementing integrated investments for each station, this approach enables Hydro One to efficiently use outages and to minimize the total number of outages required to complete necessary renewal work. The candidate investments identified through the Asset Management process include station-specific packages of work that have been developed in accordance with the established assessment cycle.

a) Has this station-focused approach historically reduced Hydro One’s costs?

b) Please show stations capital spending trends before and after this change was implemented.

c) Please rank the relative impact of this change on Hydro One's project delivery convenience, Hydro One rate base growth, improved customer service, reduced rates, and any other material parameter.

d) How does Hydro One’s 7 – 10 year assessment cycle compare with the practices of its industry peers?

Response:
a) The proportion of total transmission capital costs attributable to stations projects has remained relatively flat over the years immediately preceding and following the implementation of the station-focused approached. See response to part b) for additional details.

b) The transition to integrated station planning occurred in 2015. Actual spending and percentage of total transmission spend is shown in Tables 1 and 2 below. Prior to the change in philosophy from asset centric to station centric investments the spend increased from 49% - 60% of the total transmission capital spend. The proportion of station capital spending has remained relatively flat from 2014 – 2018 and decreases slightly from 2019 – 2022.

Spending from 2018 to 2022 is driven by the needs of customers, system reliability and overall stewardship of the transmission system. Hydro One’s proposed system renewal investments are prudent and will address deteriorated and at-risk lines and stations assets, as detailed in Exhibit B, Tab 1, Schedule 1, Section 2.2

Table 1: Stations Capital Spending Prior to Integrated Station Planning

	Actual 2009	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**
Transmission Stations Capital	224.1	284.7	262.7	322.5	355.3	481.3	565.8
% of Total Transmission Capital	24%	30%	32%	42%	49%	57%	60%

Table 2: Stations Capital Spending Post Integrated Station Planning

	Actual 2016	**Actual 2017**	**Actual 2018**	**Bridge 2019**	**Test 2020**	**Test 2021**	**Test 2022**
Transmission Stations Capital	576.3	543.6	554.9	478.4	543.7	691.9	741.1
% of Total Transmission Capital	58%	57%	57%	46%	46%	52%	54%

c) The station-focused approach is not driven by convenience or rate base growth, but is based on producing a safe, efficient and reliable system. Benefits of the station-focused approach include reduced number of outages affecting customers, reduced mobilization/demobilization activities, reduced travel time for staff, and the ability to redesign a station to optimize the number of assets which could potentially reduce future maintenance requirements. Under an asset-focused investment approach, scope was tailored to replacing assets in a like-for-like manner. This approach could result in repeated mobilization within a given year or subsequent years in order to address multiple end-of-life assets. This could result in repeated outages on the same group of assets to facilitate each replacement, placing downstream customers in an elevated risk of loss of supply due to the planned outages. Further, as focus was placed on replacing end-of-life assets like-for-like; fleet right-sizing or design standardization opportunities may have been missed, such as the consolidation of three non-standard transformers into two, larger capacity or standard units. In the previous asset-focused approach aged auxiliary components were not typically addressed in scope, and together with other factors listed identified the need for increased holistic and integrated planning.

d) Hydro One has not compared its 7-10 year station planning assessment cycle with industry peers.

OEB INTERROGATORY #21

Reference:

TSP-01-01 p. 44 TSP-01-03-04p. 1-2TSP-02-01p. 31

Interrogatory:

At the first reference above, Hydro One stated the following:

In response to concerns raised during the EB-2016-0160 proceeding, Hydro One has implemented an improved eight-step investment planning process. Key improvements to the investment planning process include:

- Consistent scoring for safety, reliability and environmental risk mitigation based on new standardized frameworks;
- Clear definitions of risk impacts to enable consistent scoring across investment types, and calibration sessions to ensure standardized scoring practices; and
- Challenge sessions, which are facilitated sessions held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs

At the second reference above, Hydro One stated the following:

In its Decision in Hydro One's last Transmission Rate Application (EB-2016-0160) the Ontario Energy Board ("OEB") found that the model[1] needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. A third party assessment completed by Metsco Energy Solutions Inc. has led to a similar conclusion and recommendations as discussed in TSP Section 1.4, section 1.4.2.14.

At the third reference above, Hydro One stated the following:

Reliability consequence information is based on realistic customer outcomes for escalating levels of consequence based on Hydro One's experience.

[1] Reliability Risk Model

a) Are the standardized frameworks based upon quantitative analysis and supported by adequate data to be replicable?

b) Is risk calculated to determine reliability risk associated with each asset under analysis:
   i. From the perspective of the asset?
   ii. From the perspective of the system?
   iii. From the perspective of Hydro One?
   iv. From the perspective of the ratepayer?

c) Given that Hydro One is not using a quantitative Reliability Risk Model (RRM) tool to estimate the marginal impact of reliability of different investments, please describe how reliability consequence is determined based on "Hydro One's experience".

Response:

a) The risk taxonomies developed for the investment planning process are fact-based, with significant analytical rigor behind the different consequence levels based on historical data.

b) Investment risk assessments for reliability are assessed based on impact to the system and customer.

c) Reliability consequence is assessed based on the Worst Reasonable Direct Impact as defined in Exhibit B-1-1 TSP Section 2.1 page 32. Determination of a "reasonable" outcome is based on an assessment of expectation based on: (i) historical events, (ii) unique characteristics of the proposed investment, and (iii) confidence in the outcome occurring.

OEB INTERROGATORY #22

Reference:
TSP-01-01, TSP-03-00

Interrogatory:
At the first reference above, Hydro One stated the following:

4. Prioritization and Optimization: The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization and optimization of investments. Following the initial prioritization and optimization, facilitated challenge sessions are held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs

At the second reference above, Hydro One stated the following:

Prioritization and Optimization: Based on risk-based prioritization and optimization through the enhanced planning process, candidate investments that are expected to most effectively mitigate the highest risk for the least cost should be performed first. For example, this is demonstrated through the prioritization and optimization of capital station sustainment work at Port Hope TS (ISD SR-05) to address emerging asset needs over a candidate investment at Havelock TS.

a) How is productivity (as used in the first reference above) assessed, quantified and integrated into these decisions? Please provide concrete examples.

b) Has the project portfolio been charted to show the risk delta achieved per dollar spent for all projects?

c) If not, why not?

d) Please provide other examples of project prioritization to demonstrate that Hydro One is following a diligent and repeatable approach.

Response:

a) In the first reference, productivity opportunities are considered, which may inform the trade-off discussion; there are varying degrees of productivity maturity. For example an information technology solution may not mitigate a significant level of risk, but may enable cost efficiencies in the future – the productivity projection is based on the level of maturity of the investment, in some cases a detailed discovery may have occurred with confirmed, validated and quantified savings, while in others a conceptual outlook may have been developed, with some uncertainty – for example a benefitting business area and notional savings identified. If an investment shows significant benefit or potential benefit, a trade-off decision may occur, within the context of risk mitigation and other factors including other mandatory and discretionary considerations.

b) Yes.

c) N/A

d) Other examples of project prioritization includes:
    a. Minden TS prioritized ahead of Hunta SS
    b. Bruce A TS prioritized ahead of Ansonville TS

OEB INTERROGATORY #23

Reference:
TSP-01-01, TSP-01-04, TSP-01-04-15

Interrogatory:
At the first reference above, Hydro One stated the following:

Figure 10 shows the forecasted cumulative number of assets that will exceed their expected service life during the 2019 to 2029 period in the absence of any planned or unplanned replacements. Over this period, the number of assets that are beyond the expected service life in these asset classes would increase by 1.8 to 3.6 times current levels.

At the second reference above, Hydro One stated the following:

The results of this study based on current condition assessment data and historical overhead conductor replacement data, indicate that ESL for overhead conductors in the Hydro One transmission system should be approximately 90 years. Hydro One's assigned ESL for overhead conductors was set at 70 years before this study. The new ESL resulting from this study does not affect the current business plan as identified replacements are not age based decisions, they are based on verified asset condition.

At the third reference above, Hydro One stated the following:

Investment Development
Hydro One’s transmission assets are replaced as condition warrants through rigorous testing. However, a backlog of asset condition testing has developed for assets such as conductors and shieldwire, where a large portion of the asset base is approaching it’s Expected Service Life (“ESL”).

a) Please explain why the “1.8 to 3.6 times” statistic is meaningful in this context.

b) Hydro One has recently changed its expected service life for conductors from 70 years to 90 years, indicating that there is a significant range of uncertainty associated with Hydro One’s expected asset service life values. Is Hydro One able to demonstrate that similar adjustments are not required for other asset classes, or that further adjustments are not needed for conductors?

c) Is Hydro One able to demonstrate quantified correlations between exceedance of expected service lives for individual asset classes and system reliability performance? If yes, please provide tables showing these relationships.

d) Is conductor-km as used in Figure 10 above the same as circuit-km? For example, if there is a 1 km three phase transmission line strung with quad bundled conductor, is that equal to 12 km or 1 km?

e) Has Hydro One recorded any increase in the rate of conductor failures or outages caused by conductor failures?

<u>Response:</u>

a) "1.8 to 3.6 times" shows an increasing trend across all major assets. As equipment approach their ESL, the likelihood of it being in a deteriorated state increases. Therefore as the average age of an asset fleet increases, we expect to find a greater number of deteriorated assets within that fleet.

b) Hydro One continues to track and monitor the performance of its asset fleet to maximize equipment utilization, while managing the associated risks. Where warranted, Hydro One reevaluates the ESL of an asset type to apply continuous improvement. More recently, as summarized in Interrogatory I-12-AMPCO-033, Hydro One updated the ESL for three asset types (ACSR conductor, HPLF and LPLF cables). The report found at Exhibit B-1-1 TSP 1.4 Attachment 4 reflects the most current assessment of Hydro One's ACSR conductor fleet and provides no indication of a necessity for further adjustments going forward.

c) Hydro One aims to proactively replace its deteriorated assets before they fail in order to avoid a negative impact on system performance. As such, the relationship between assets that exceed ESL and reliability would include the effect of Hydro One's proactive efforts to remove poor condition assets that might otherwise have caused an unplanned outage.

d) Conductor-km here equals to circuit-km. 1 km three phase transmission line strung with quad bundled conductors, is equal to 1 km.

e) As discussed in Exhibit B-1-1, TSP 2.2, the number of forced outages due to conductor failures has improved over the past ten years while the outage duration has been relatively stable over the same period. However, Hydro One aims to proactively replace its deteriorated assets before they fail. As such, meaningful correlation between failure rates and fleet/system condition is not available. As noted in Interrogatory I-01-OEB-120 part e) i) and discussed in See I-01-OEB-125, between 2008 and 2018, 36 delivery points were interrupted as a result of failures along the 1903 circuit-km of ACSR conductor planned for replacement. This corresponds to 0.02 delivery point interruptions per km. In comparison, the overall fleet of 29,107 circuit-km of conductor experienced 126 delivery point interruptions between 2008 and 2018. This corresponds to 0.004 delivery point interruptions per km. Therefore, the 1903 circuit-km of conductor planned for refurbishment is presently demonstrating five times more delivery point interruption when compared to the overall fleet.

OEB INTERROGATORY #24

Reference:

TSP-01-01 p. 48-49 TSP-01-03-04 p.1-2

Interrogatory:

At the first reference above, Hydro One stated the following:

In developing the TSP, Hydro One recognized that execution of the plan will take place in the context of the broader Ontario power system. In determining the timing and pacing of its investments, Hydro One considered both its own ability to execute capital and OM&A work efficiently and its ability to secure planned outage time to minimize impacts on customers and other stakeholders in Ontario. As a result, it has planned the pace of renewal work so that certain critical work to reduce risk on the system could be completed in the next five years to ensure that transmission assets are in service and not subject to increased outage constraints resulting from increased failures or additional maintenance that would make the work more difficult to complete.

At the second reference above, Hydro One stated the following:

In its Decision in Hydro One’s last Transmission Rate Application (EB-2016-0160) the Ontario Energy Board (“OEB”) found that the model[1] needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. A third party assessment completed by Metsco Energy Solutions Inc. has led to a similar conclusion and recommendations as discussed in TSP Section 1.4, section 1.4.2.14.

a) Is the described situation expected to change beyond the five-year planning horizon?

b) Please show the quantified analysis used to determine which "critical work" must take place to reduce risk on the system, given that the METSCO report (filed under TSP Section 1.4 Attachment 13) indicates that Hydro One's risk analysis does not adequately measure the system reliability risk associated with individual assets.

[1] Reliability Risk Model

Response:

a) Refurbishments at major generation stations, including OPG's Darlington Nuclear Generating Station and the Bruce Nuclear Generating Station are expected to extend to the mid-2030s.

b) Please refer to OEB-21 part c; Hydro One has implemented an improved investment planning process which includes a prioritization based on assessed risk to safety, reliability and environment.

OEB INTERROGATORY #25

Reference:
TSP-01-01 p.50,A-03-01 p. 26
Table 5

Interrogatory:
At the first reference above, Hydro One stated the following:

System Access and System Service
The TSP funds $947 million of System Access and System Service capital that is required over the planning period to provide transmission access and additional capacity for new customer connections and to implement regional development plans that were developed jointly with customers, transmitters, distributors and the IESO. These investments will result in the addition of seven new transformer stations, ten customer-owned stations and 272 circuit km of new or upgraded transmission lines. Major projects include the development work for the North-West Bulk transmission expansion, new transmission switching and lines facilities to support load growth in the Leamington area, transformation and lines at Milton Switching station, and upgrades/expansion in Barrie and Toronto areas.

The second reference is Hydro One’s 2020-2022 Load Forecast

a) Given that Hydro One's peak load is forecast to decline throughout the planning period (per Table 5 above), are there areas in the system where peak load is dropping off significantly to offset these identified areas with growing loads that require additional localized system capacity?
   i. If yes, please explain how Hydro One prioritizes replacement of assets that are beyond their expected service lives in these shrinking load areas, given that the peak loading of the associated assets is declining each year.

Response:
a) No, there are no areas where local peak load used for system planning is dropping significantly.

OEB INTERROGATORY #26

Reference:
TSP-01-01p. 52

Interrogatory:
At the above noted reference, Hydro One stated the following:

Approximately $590 million of the identified savings opportunities are related to Operations (Operations OM&A, Operations Capital, Progressive Operations (Defined Capital) and Progressive Operations (Undefined Capital), approximately $44 million in savings are IT-related (OM&A and Capital) and approximately $70M in savings are related to Corporate Initiatives (OM&A and Capital).

Hydro One expects to achieve these significant cost savings over the forecast period through good planning and effective execution of the TSP.

a) Please categorize the projected capital savings as: i. Capital delivery efficiencies; ii. Capital project scope reductions; iii. Capital projects deferred or eliminated.

b) Please categorize the projected OM&A savings as: i. Staff reductions; ii. Contractor invoice reductions; iii. Consumable reductions.

c) Are there any other savings not identified above? If yes, please quantify.

d) Is "good planning and effective execution of the TSP" a different approach than has been applied in past test periods?
   i. If no, how will savings be produced?
   ii. If yes, please provide a detailed explanation of what has changed and quantify, to the extent possible.

Response:
a) All savings would be in the form of Capital delivery efficiencies. Hydro One does not quantify things like project scope reductions or deferral/elimination of projects as productivity. The latter would be considered cost avoidance. Cost avoidance is a good

business practice that is followed by Hydro One; however, cost avoidance is not quantified as part of Hydro One's productivity plan.

b) Hydro One's productivity initiatives are discussed in detail in B-1-1 TSP Section 1.6 Heading 1.6.2.2 Productivity Savings in the Plan. The referenced exhibit will provide more context to the table presented in TSP-01-01 by category. Hydro One's savings initiatives are broader than the proposed categories.

Further detail can be found in Exhibit I, Tab 07, Schedule SEC-26, including a list of specific productivity initiatives impacting OM&A, Capital and Corporate groups.

Specific OM&A initiatives affecting the above categories include:

i) Staff reductions
   a. Engineering Software implementation
   b. Corporate Initiatives (OM&A and Capital)
ii) Contractor Invoice Reductions
   a. Information Technology Contract Renegotiation
   b. Procurement
   c. Corporate Initiatives (OM&A and Capital)
iii) Consumable reductions, or 'Scope Reduction' is not something Hydro One tracks as part of the productivity program.

c) Hydro One has included all known savings opportunities and incremental Progressive Productivity targets into the 5 year TSP. Please see B-1-1 TSP Section 1.6.

d) The phrase "good planning and effective execution of the TSP" does not reflect a new approach, rather reinforces Hydro One's ongoing commitment to delivering outcomes valued by customers. Hydro One has continued to build on a performance management culture, implementing a governance and control framework which includes productivity initiatives and associated savings, as described in Exhibit B, Tab 1, Schedule 1, Section 1.5, Attachment 1.

OEB INTERROGATORY #27

Reference:
TSP-01-02 p. 15,16 & 18

Interrogatory:
At the first reference above, Hydro One stated the following:

Greater Ottawa:
The second cycle NA report for this region was published in June 2018. The NA continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following additional system renewal investments over the 2020 to 2024 period:

- Arnprior TS: Transformer (T1/T2) Replacement (Part of SR-02);
- Longueuil TS: Transformer (T3/T4) Replacement (Part of SR-05);
- Slater TS: Transformer (T1/T2/T3) Replacement (Part of SR-02); and
- 115kV S7M Transmission Line: Refurbish line sections (SR Other Projects).

At the second above reference, Hydro One stated the following:

GTA North:
The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

a) Given that the RIP for the second cycle has not yet been issued for the Greater Ottawa region, is it premature for Hydro One to be proposing these investments for implementation in the present application period?

b) Similarly, given that the second cycle IRRP phase led by the IESO is still underway for the GTA North region, is it premature for Hydro One to be proposing these investments for implementation in the present application period?

c) Could these investments be deferred into the next filing? If no, why not?

Response:
a) As documented in Exhibit B, Tab 1, Schedule 1, TSP Section 1.2, the Regional Planning Study Team assess needs and makes recommendations in each phase (NA,

IRRP or RIP) of regional planning. Ultimately all needs and recommendations are consolidated in the RIP report for the region. Planning assessment and final recommendations for the Greater Ottawa region have been made by the Regional Planning Study Team in the NA phase so it is not premature for Hydro One to propose implementation of the investments planned for in-service in the 2020 to 2022 period in the present application. Also note that not all four projects referenced are planned for in-service within the 2020 to 2022 period and as such approval for investments beyond 2022 will be part of a future rate application.

b) The two investment needs identified in the NA report for the GTA North region are planned for in-service outside of the 2020 to 2022 period of Hydro One's present rate application and will be part of a future rate application. The purpose for inclusion of the five year capital plan investment details was only to satisfy the OEB Chapter 5 filing requirements and not to seek approval at this time.

c) Projects identified in this rate application for in-service in the 2020 to 2022 period cannot be deferred as they will compromise safe, secure and reliable supply to customers (i.e. one of the Slater TS transformers TI failed and had to be replaced). However as noted in part (a) and (b) some of the projects listed in the NA reports are planned for in-service beyond 2022 and will therefore be part of a future rate application.

OEB INTERROGATORY #28

Reference:

TSP-01-02 p. 19

Interrogatory:

At the above noted reference, Hydro One stated the following:

GTA West

In response to the RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- Connection of a new load station “Halton TS #2” (Project SA-03);
- Milton SS: Station Expansion and Connect 230kV circuits (Project SS-07); and
- Reconductor 230kV H29/H30 Transmission Line (SA Other Projects).

a) Please state whether the primary driver for the Reconductor 230 kV H29/H30 Transmission Line Project is conductor condition or ampacity.

Response:

a) The primary driver for the Reconductor 230kV H29/H30 Transmission Line Project is ampacity.

OEB INTERROGATORY #29

Reference:
TSP-01-02-02 p. 48

Interrogatory:
At the above noted reference, Hydro One stated the following:

7.17 Newton TS End of Life Transformers and Switchgear
Newton TS is a 115 kV/ 13.8 kV DESN station having transformers built in 1956 and supplies Alectra Utilities loads in the city of Hamilton. It has two station supply transformer of 67 MVA each supplying loads through its 13.8 kV switchyards. The customer load at the station is about 50 MW and is forecasted to stay at the same level in the foreseeable future. Hydro One in initial assessment has identified that both transformers and switchgear requiring refurbishment. The scope of refurbishment is subject to final asset condition assessment of Newton TS to be completed in 2017.

a) What was the result of the final asset condition assessment?

b) Has Hydro One updated the plans for the Newton TS based on these results? If yes, what was changed?

Response:
a) Hydro One asset condition assessment and inspection confirmed the results of the initial assessment: that it is necessary to replace of transformers T1 and T2, the associated transformer disconnect switches and protections and AC station service transfer scheme.

b) Given that the results of the final condition assessment were consistent with the initial assessment, the plans for Newton TS have not materially changed in terms of the replacement of primary equipment i.e. transformers T1 and T2.

OEB INTERROGATORY #30

Reference:

TSP-01-02-05 p. 22
Figure 5-1

Interrogatory:

a) Are updated current year peak load forecasts available for this area and any other planning regions which have identified the need for capacity-related asset additions/expansions? If yes, please provide revised figures for each region.

b) For each of the updated load forecast figures provided in part a), do the updated forecasts change any of the needs identified in the RIPs? If yes, please describe the resulting changes.

Response:

a) The current peak load forecast for the GTA North region referenced above and any other Group 1 regions with a completed second cycle Needs Assessment (“NA”) are presented in the NA reports noted in Exhibit B, Tab 1, Schedule 1, TSP Section 1.2. Updated peak load forecasts will be published in the upcoming second cycle Integrated Regional Resource Plan (“IRRP”) or RIP report.

b) Please see response to part (a). The updated load forecasts will be published in the upcoming IRRP or RIP report. The NA report has identified some incremental changes (and in some instances deferral) to needs in the region as documented in Exhibit B, Tab 1, Schedule 1, TSP Section 1.2. These needs and any further changes required resulting from the regional planning process will be documented in the upcoming RIP.

OEB INTERROGATORY #31

Reference:
TSP-01-02-08 p. 39
Table 7-2

Interrogatory:

a) What is the present status of the Metrolinx electrification project timing?

b) What is the resulting impact upon the capacity upgrade projects identified in this RIP (and any other RIPs included in this filing which incorporate Metrolinx electrification needs)?

Response

a) Metrolinx electrification is part of the Government of Ontario Regional Express Rail ("RER") expansion program. The scope and timing of these Traction Power Station ("TPS") projects will be determined by the successful bidder that is selected to undertake the RER project. The final bidder selection process has only just started. The status of the project is provided at the following link:
https://www.infrastructureontario.ca/RER-GO-Regional-Express-Rail-Corridor/#pDetailStatus

b) As shown in Table 7-2 (Exhibit B-1-1, TSP Section 1.2, Attachment 8 page 39) the Richview TS to Manby TS upgrade project is required by 2023 even in the absence of the Metrolinx project. Any delay in the need for the Mimico TPS has thus little impact on the need date for the Richview TS x Manby TS upgrade project.

The planned 230kV Essa TS x Barrie TS transmission lines project will also supply the proposed Metrolinx Allandale TPS (Exhibit B-1-1, TSP Section 1.2, Attachment 13 page 39). However, since the TPS will be built after the new line is built; the electrification project has no impact.

OEB INTERROGATORY #32

Reference:

TSP-01-02-08 p. 44
Table 8-2

Interrogatory:

a) Have projects 1 & 2 been completed, are they in construction, or are they deferred to the present filing?

b) If projects 1 & 2 were deferred to the present filing, is the urgency of these projects overstated in this RIP?

c) Are projects 3 & 4 included in the present filing?

Response:

a) Both Project 1 (Manby SPS) and Project 2 (Runnymede Expansion & 115kV Manby x Wiltshire Corridor Upgrade) are complete. Project 1 was completed in July 2019. Project 2 was completed in November 2018.

b) Please see response to part (a) above. These projects are not part of Hydro One's 2020 to 2022 Rate Application and their urgency was not overstated in the RIP report.

c) Yes, Project 3 (Horner Expansion) and Project 4 (230kV Richview x Manby Corridor Upgrade) are included in the present filing as noted in ISD's SA-02 and SS-14 respectively in Hydro One's Transmission System Plan (Exhibit B, Tab 1, Schedule1).

OEB INTERROGATORY #33

Reference:
TSP-01-02-09 p. 39

Interrogatory:
At the above noted reference, Hydro One stated the following:

In the medium load growth scenario, involving new mines and industrial load (one pumping station of the Energy East gas-to-oil pipeline development supplied from the Thunder Bay transmission system) and no change in the pulp and paper sector, the load is forecasted to increase to 400 MW in 2035.

a) Given that the Energy East project is no longer active, can the medium scenario now be reduced commensurately?

b) What is the impact on the requirements identified in this RIP?

Response:
a) The Regional Planning Study Team diligently considered low, medium and high load growth scenario to identify any mitigations and associated investment in the absence of firm projects. In light of the fact that Energy East project is no longer active, the load forecast scenario will be adjusted/updated as part of the second cycle of the regional planning process. This is consistent with the RIP report indicating that the needs for the region were to be reassessed as part of the next planning cycle.

b) The needs identified in the RIP for the Thunder Bay sub-region were only indicative based on a scenario and were expected to be reassessed as part of the next planning cycle, as noted in response to part (a) above. There is no impact to Hydro One’s current application for 2020 to 2022 rates.

OEB INTERROGATORY #34

Reference:
TSP-01-02-10 p. 29; Figure 6-1

Interrogatory:

a) Please explain the reason for the abrupt discontinuity between the historical and forecast period demand trends for the Kingsville-Leamington Subsystem.

b) Is an updated 2019 version of this chart available? If yes, please provide it.

c) Does the revised forecast change the need of any projects identified in the Regional Plan?

Response:

a) The reason for the abrupt discontinuity between the historical and forecast period demand trends for the Kingsville-Leamington Subsystem is due to unprecedented and continued load growth in the area, as described further in response to part (b) below.

b) No, an updated forecast for this subsystem is not available at this time. However, a forecast is being developed as part of the second cycle of the Integrated Regional Resource Plan ("IRRP") process for the Region. In the course of this IRRP, the IESO has issued a transmission line handoff letter to Hydro One (please refer to Appendix A to this response) to develop a new transmission line. As per this letter:

> *"There has been a significant increase in the demand forecast for electricity in the Kingsville–Leamington area. Primarily, this is driven by rapid expansion in the greenhouse sector and aggressive adoption of artificial crop lighting. As a result, the electricity demand in the Windsor-Essex region is forecast to double over the next five years and continue to grow in the longer term beyond that."*

c) There is no change to the need for the projects already identified in the Regional Plan as a result of the increased forecast. However, the revised forecast is expected to result in the need for significant additional facilities in the Leamington area as documented in ISD SS-13 of Hydro One's Transmission System Plan (Exhibit B, Tab 1, Schedule 1).

Appendix A: IESO Handoff Letter to Hydro One

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January 31, 2019

Darlene Bradley
Vice President, Planning and Engineering
Hydro One Networks, Inc.
483 Bay Street
Toronto, ON M5G 2P5

Dear Darlene:

Re: Establishing a switching station in the Leamington area to accommodate demand growth

The purpose of this letter is to request that Hydro One establish a new switching station at or near Leamington Junction to sectionalize and switch the four existing 230 kV circuits from Chatham to the Windsor area (C21J/C22J/C23Z/C24Z).

A number of system improvements have been identified as part of the ongoing Windsor-Essex Integrated Regional Resource Plan ("IRRP") and bulk transmission planning study for the broader West of London area. Based on the forecast demand growth in the Kingsville-Leamington area, these planning activities identified the need for a new switching station at the Leamington Junction as an outcome of the initial study work and will form a basis for additional supply reinforcements to the area.

The switching station will increase the capability of the system to supply load in the Kingsville-Leamington area while contributing to improved performance of the bulk system. The nature and timing of the need, as well as the objectives and scope of the recommended solution, are described below in more detail.

Background and Project Objectives

The Kingsville-Leamington area encompasses two existing load supply stations, Kingsville TS and Leamington TS. Over 600 MW of load is forecast to materialize in the area by 2022, predominately in the area supplied by Leamington TS. The growth is driven by rapid expansion in the greenhouse sector and aggressive adoption of artificial crop lighting, primarily in the winter months, and is forecast to continue beyond 2022.

Both Kingsville TS and Leamington TS are forecast to reach their station capacity within the next year. An expansion to Leamington TS, which will double the station's capacity, is currently under development by Hydro One and is expected to be in-service by the end of 2019.

The transmission system supplying Leamington TS is currently limited in its capability to serve the expanded station. In order to accommodate the expansion of Leamington TS and connection of two additional transmission customers, interim measures are required. The resulting system will have a lower level of reliability than what is typically provided. Beyond these connections and interim measures, the existing system does not have the ability to accommodate the total amount of forecasted load.

The proposed switching station will improve reliability, and provide some additional local supply capability to connect an additional transformer station and continue supplying load in the Kingsville-Leamington area. Upstream transmission limitations are still anticipated but can potentially be mitigated by interim congestion management strategies.

Various alternatives were considered including non-wires options and other wires solutions. Due to the magnitude and the timing of the need, non-wires options alone are not sufficient. A generation option located at Leamington Junction was considered but was impractical due to the technical infeasibility and high anticipated cost. An option to build a new radial 230 kV line from Chatham SS to Leamington TS was also ruled out on the basis that the load meeting capability would be insufficient to meet the forecasted load growth and the solution would not provide the flexibility to supply future growth beyond the Leamington TS expansion.

In addition to improving load supply capability in the Kingsville-Leamington area, the proposed switching station will improve the performance of the bulk system by balancing the flow on the existing transmission circuits from Chatham, thus improving transfer capability. The switching station will also reduce exposure to outages by allowing the existing 230 kV circuits to be sectionalized and switched independently. Furthermore, it will allow for future transmission reinforcements to increase the transfer capability west of Chatham which will allow existing export capability to Michigan to be maintained while enabling additional load growth throughout the Windsor-Essex region.

Project Scope

The purpose of the proposed switching station is to improve the performance of Hydro One's facilities in the region. The switching station bisects Hydro One owned transmission circuits and will require a number of planned outages to Hydro One's existing assets. The switching station should ideally be constructed within Hydro One's existing right-of-way at or near the existing Leamington Junction to optimize utilization of existing infrastructure and minimize lead time. Based on the above considerations, the IESO recommends that Hydro One proceed with establishing the switching station including pursuing the required environmental and regulatory approvals.

The scope of the project will include re-termination of the four existing 230 kV circuits and installation of reactive facilities based on current system needs. Additionally, the station should be sized to accommodate future system reinforcement including space for future diameters and additional reactive facilities. The IESO will continue to work with Hydro One throughout the project development to finalize the layout of the switching station.

Given typical development timelines for similar projects, the IESO and Hydro One agree on a targeted in-service date of 2022 dependent on outcome of consultations as well as environmental and regulatory approvals. The IESO understands that consultations and a Class Environmental Assessment process will be required for this project. Additionally, depending on the siting of the switching station, a Leave to Construct may be required. The IESO will endeavour to provide support to Hydro One in these activities.

Future Work and Next Steps

The switching station is one of a number of improvements that will be required to support load growth in the Windsor-Essex area and forms the basis for future recommendations to meet mid- and long-term needs.

In parallel to the activities identified in this letter, the IRRP's Technical Working Group[1] will continue to develop the long-term plan for the Windsor-Essex region. This will include an investigation of non-wires alternatives to manage evolving capacity needs in the region, and may include specifying other long-term solution(s) required to reliably serve forecasted load growth. The IESO will also be proceeding with the bulk transmission planning study for the West of London area and identifying any additional solution(s) required for the broader area.

The IESO will continue to work with, and provide support to, Hydro One in the implementation of this project, including finalizing the layout of the switching station facility. We look forward to an ongoing exchange of information as Hydro One proceeds with the development of the project.

Yours truly,

Leonard Kula, P. Eng.
Vice President, Planning, Acquisition and Operations, and Chief Operating Officer

cc: Robert Reinmuller, Hydro One Networks Inc.
Terry Young, IESO
Jessica Savage, IESO
Bob Chow, IESO
IESO Records

[1] The IRRP Technical Working Group for the Windsor-Essex Region is led by the IESO and includes members from Hydro One Transmission, Hydro One Distribution, Essex Powerlines, Entegrus, E.L.K. Energy, and Enwin.

Appendix: System Maps

Figure 1: Geographical map of the Windsor-Essex Region

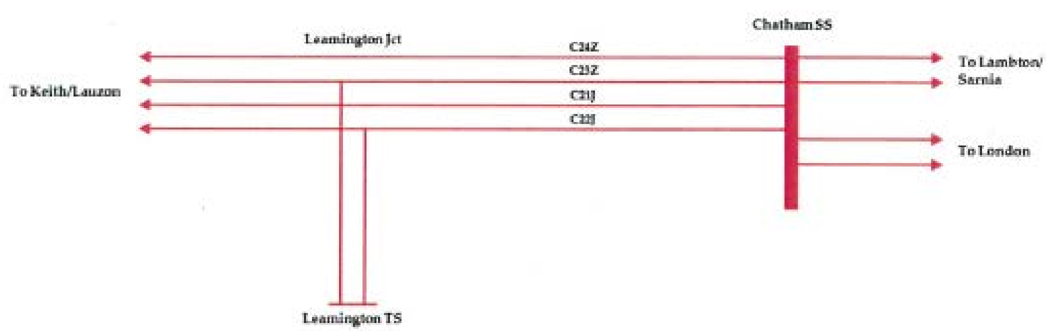

Figure 2: Single line diagram of existing facilities in the Leamington area

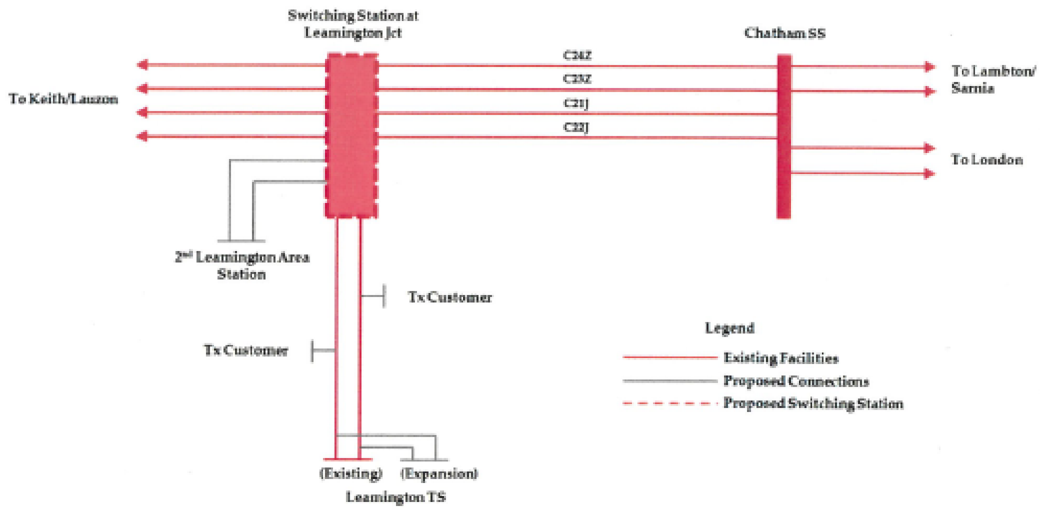

Figure 3: Single line diagram of existing and proposed facilities in the Leamington area

OEB INTERROGATORY #35

Reference:
TSP-01-02-11p. 24 & 39
Figure 5-1

Interrogatory:
At the second reference above, Hydro One stated the following:

As discussed in Section 5, the electricity demand in the London Area Region is expected to remain relatively constant over the study period (approximate growth rate of -0.3%). Load growth over the long term period is expected to be moderate (up to 1.5%) from 2027 to 2037. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

a) Please provide a more current update of Figure 5-1.

b) Does the load growth turnaround vs. the historical load shrinkage still exist in the updated forecast?
   i. If yes, what is changing over the long term to cause the forecast load growth turnaround?

Response:
a) An update to load forecast is undertaken with input from local distributors along with municipalities in the area during the regional planning process. An update to the reference Figure 5-1 will be undertaken in the upcoming second cycle of the regional planning process.

b) Please see response to part (a) above.

OEB INTERROGATORY #36

Reference:
TSP-01-02-11 p. 40
Table 8-2

Interrogatory:

a) What is the primary driver for the replacement of transformer T5 at the Wonderland TS; capacity constraint, asset condition or other?
   i. If asset condition, what does the most recent asset condition report indicate about remaining life of this asset?

b) How critical is this transformer to serving local loads?

c) Can anything be done to defer this expenditure given the anticipated regional load shrinkage?

Response:

a) The primary driver for the replacement of transformer T5 at Wonderland TS is poor asset condition. The transformer, built in 1966, has experienced excessive gas discharge, persistent oil leaks, tap changer failures and cooling related failures that confirm the accelerated equipment degradation.

   The transformer was forced out of service on July 8th, 2019 due to a failed dissolved gas analysis test. Hydro One is now proceeding with an emergency replacement of the T5 transformer.

b) Wonderland TS is the sole supply point serving the southwestern part of the city of London and it represents approximately 15% of the city's total demand. There is limited capacity to transfer loads currently served by Wonderland TS to neighbouring transformer stations.

c) No, load shrinkage has no impact on the need to replace transformer T5 at Wonderland TS. There is no practical alternative to this work. Please see responses to parts a) and b). With T5 out of service, any outage of the remaining station transformer T6 would result in loss of supply to area customers.

Witness: Donna Jablonsky, Robert Reinmuller

OEB INTERROGATORY #37

Reference:
TSP-01-04-13 p. 26 & 34

Interrogatory:
At the first reference above, Hydro One stated the following:

Note 5: Parry Sound TS was placed in service in 1970 and has been supplying power to parts of the Region for almost 50 years. Field crews have recently observed that one of the two power transformers is in poor operating condition.

At the second reference above, Hydro One stated the following:

Based on historical demand data and the station's net demand forecast, Parry Sound TS T1/T2 has already exceeded its respective normal supply capacity and will continue to do so over the study period. Parry Sound TS is a winter peaking station with a winter LTR of 52 MW. It had exceeded its LTR by as much as 6 MW in the winters of 2013 to 2016, however the 2017 winter peak was 8 MW below the LTR.

a) Has a more recent fulsome asset condition assessment been carried out on the Poor Condition transformers at Parry Sound TS since this report was written (August 18, 2017)?
   i. If so, who carried out the assessment and what were the findings/recommendations?

b) What caused the 2017 peak load reduction?

c) Please provide the 2018 peak load results.

d) Is this indicative of a trend change towards longer-term peak load decreases?

Response:
a) A fulsome asset condition assessment on the Parry Sound T1 Transformer was carried out in 2017, and due to its poor condition, a recommendation for replacement was provided as stated in the T1 Transformer Assessment Report issued on Nov 20,

2017). During the annual screening process for transformer asset investment planning, the Parry Sound T1 transformer's poor operational condition was re-confirmed and this transformer was scheduled for replacement with an expected in-service date in 2023. Parry Sound T2 transformer is in a fair operational condition and will be maintained and closely monitoring.

Findings related to the Parry Sound T1 transformer:

- Built in 1969 and in-serviced in 1970, Parry Sound T1 is a 25/33/42MVA, 230-44kV, 3 phase transformer with an on-load tap changer.
- The T1 transformer at Parry Sound has been reviewed and assessed based on: 1) Demographics, 2) Equipment conditions, 3) Potential or existing environmental/ HSE hazards, 4) Loading and 5) Economics.
- DGA analysis concluded that T1's oil has acetylene that is beyond acceptable limit. T1 also shows incipient signs of insulation deterioration.
- Loading on T1 has been within the nameplate and LTR rated limits in general, but has been loaded beyond nameplate from December 2014 to February 2015 during companion bank (T2)'s outage.
- NPV analysis indicates that it is cheaper to remain status quo, the difference between replacement vs major refurbishment is minimal.
- Recommendation for replacement within the next 5 years to mitigate reliability risk and lower lifecycle cost.

b) The RIP (Regional Infrastructure Planning) report was published in August of 2017, and historical data was only available for the first half of the year. The actual 2017 peak was 54 MW (2MW above the LTR), which occurred in the last week of December and falls within the historical loading trend of the station.

Year	**Peak Load MW (Winter)**
2014	60
2015	60
2016	58
2017	54
2018	54

c) See b) above

Witness: Donna Jablonsky, Robert Reinmuller

d) It is not indicative of a downward trend or peak load decreases.

OEB INTERROGATORY #38

Reference:
TSP-01-04-13 p. 31

Interrogatory:
At the above noted reference, Hydro One stated the following:

It is worth noting that there are potential bulk power system elements that are also at the end of their useful lives. These include 230 kV transmission lines D1M/D2M, E8V/E9V, and M6E/M7E. IESO will lead the bulk power system studies for these lines in coordination with Hydro One.

a) Is the asset condition assessment for these facilities Hydro One's responsibility?
   i. If no, please explain why not.

b) What will be the IESO's role in this analysis?

Response:
a) Yes.

b) The IESO’s role in this analysis will be to work with Hydro One to assess if like for like replacement including right sizing vs. enhancement, elimination or a new configuration will be a better option.

Witness: Donna Jablonsky, Robert Reinmuller

OEB INTERROGATORY #39

Reference:

TSP-01-03
(1) pp.6-7 Figure 2
(2) p.8
(3) Attachment 1, p. 5
(4) Attachment 1, p. 15

Interrogatory:

At the first reference above, Hydro One stated the following:

Hydro One's Transmission Customer Engagement Survey process yielded valuable feedback concerning the specific needs and preferences of its transmission-connected customers to shape Hydro One's investment plans.

At the second reference above, Hydro One stated the following:

Cost was also raised at various times throughout the survey. The desire for good reliability at a competitive or low cost was universal.

At the third reference above, Hydro One stated the following:

Customer Outcomes

Hydro One and INNOVATIVE reviewed previously available documents and talked to customer-facing Hydro One staff in order to develop a list of customer outcomes that was included in the survey. Prior to being exposed to this list, an open-ended question designed to elicit outcomes in customers' own words was asked. In response to this open-ended question, transmission customers said they know Hydro One is doing a good job for their business based on reliability, and customer service/communication (both of which were included in the list of outcomes developed for the survey).

At the fourth reference above, Hydro One stated the following:

Performance Criteria:

Reduction in outages and interruptions, power supply, and customer service in terms of communication are top mentions for performance metrics.

a) Given that the "desire for good reliability at a competitive or low cost was universal", why doesn't Hydro One consider Cost as one of the Customer Outcomes to be ranked when setting priorities for Hydro One's business plan?

b) Is the reason Low Cost is not included in the ranked list of Customer Outcomes because it is ranked below the other identified outcomes (i.e. Safety, Productivity, Reliability, Outage Restoration, Power Quality, Customer Service, and Environmental Stewardship)?
   i. If not confirmed, please provide a revised ranking of Customer Outcomes that includes Low Cost, and provide the evidence on which Hydro One makes this ranking determination.

c) Regarding the Customer Outcomes, how did Hydro One translate the information gathered and represented in Figure 2 to actionable information?
   i. For example, do the results represented in Figure 2 suggest that Hydro One is not doing enough regarding "Safety"?

d) Please provide details on what changes Hydro One made to its capital expenditure planning processes (for example, by increasing or decreasing consequences within the risk management process) as a result of the findings in Figure 2 - Customer Outcomes. For each response below, please provide examples.
   i. Did Hydro One change its approach to either Safety or Environmental Stewardship, and did that result in the acceleration or deceleration of certain CAPEX projects?
   ii. How did Hydro One alter its productivity programs plans discussed in TSP Section 1.6 in response to customer feedback?
   iii. Did Hydro One ask any follow-up questions that explain why customers do not seem to favour Hydro One emphasizing higher productivity, which implies that Hydro One would be trying to provide more benefit relative to its input costs?

e) Hydro One and Innovative developed the list of Customer Outcomes (Figure 2), however when asked "How do you know if Hydro One is doing a good job for your business?" Hydro One's customers did not reference Safety, Productivity or

Environmental Stewardship. Is this a fair statement? If so, please explain this disconnect.

Response:

a) For the purposes of developing an investment plan for the transmission system, it is important to understand customer preferences relative to each other. Cost is a certain outcome of any investment so its relative ranking was determined to be less informative as a stand-alone outcome. Rather, customers were provided an opportunity to indicate the importance of cost relative to outcomes through four illustrative scenarios with associated impacts including but not limited to rate and reliability impacts. See Hydro One's Customer Engagement Survey Report at Exhibit B-1-1, Sec 1.3, Attachment 1, pages 44-52.

Hydro One does consider cost a customer outcome. For example, during the customer consultation, under the "Productivity" outcome, customers were presented with the following: "*Implementation of new technologies and processes to enable operational efficiencies in the planning and execution of work programs aimed at reducing costs and more efficient use of resources. Hydro One understands that customers expect it to look first for internal savings before asking for any additional rates. How important an outcome is productivity?*" (Exhibit B, Tab 1, Schedule 1, Section 1.3, Attachment 1, page 23.) Further, as part of Hydro One's Strategic Priorities, Operational Effectiveness includes a "*Focus on continuous improvement in productivity and operating efficiency to maintain lowest possible costs*" (Exhibit B, Tab 1, Schedule 1, Section 2.1, page 5).

b) No. Low Cost was not asked to be ranked.
   i. The list cannot be revised to include Low Cost as this information does not exist. Please refer to a) above.

c) Please refer to Exhibit B, Tab 1, Schedule 1, Section 1.3, subsection 1.3.6.2 which summarizes alignment between customer outcomes, Hydro One's risk scoring process, and the use of the Customer Engagement flag to provide additional context to trade-off discussions.
   i. No, Figure 2 does not suggest that Hydro One is not doing enough regarding "Safety"; rather it indicates that "Eliminating and mitigating risk to public and employee safety in the operation of the transmission system" is extremely

important to customers and that Hydro One should continue to maintain a focu on safety.

d) Please see below:

i. The customer engagement feedback reinforced that safety and environment wei important considerations for customers; as a result, certain investments wei accelerated or decelerated such as the deferral of wood pole replacements in noi publicly accessible areas.

ii. Hydro One has embedded significant productivity savings into the Transmissic System Plan, reflecting a commitment to continuous improvement to delive Hydro One's work program at a lower cost.

iii. No.

e) No, this is not a fair statement. In the customer verbatim responses included i Exhibit B, Tab 1, Schedule 1, Section 1.3, Appendix 1.1, customers did referenc both safety and productivity, including:

i. "Open dialogue and regular face to face visits reassure us HO understands tł impacts of safe reliable operations"

ii. "Costs to businesses are kept in control. Evidence that cost control at Hydro Or is in place and effective."

Beyond these , when you compare the open-ended responses to the closed-ende responses, the key difference is that some outcomes are "table stakes", things th are important but taken as a given. For instance, safety receives the highest ratir for importance but receives relatively few open-ended mentions not because it unimportant but because TX customers are generally satisfied with the experience on this very important dimension.

Productivity is relatively less important on the rating and ranking but that does n mean it is unimportant. Thirty seven (37) customers rate it a 10 and another 4 give it an 8 or a 9. End users are more likely to give it a higher rating and w anticipate that is also true of end-users served by LDCs.

Further, environmental stewardship is reflective of public policy responsiveness, key outcome identified by the OEB in the Renewed Regulatory Framework.

OEB INTERROGATORY #40

Reference:
TSP-01-03 p. 7

Interrogatory:
At the above noted reference, Hydro One stated the following:

The key messages and results received by Hydro One from the 2017 Transmission Customer Engagement Survey are as follows:

- Reducing the frequency of outages is more important than reducing the duration of outages. However, the most important issue is to reduce the number of day-to-day interruptions.

a) Please explain how Hydro One incorporated the above noted key message into its planning process.
   i. Please provide specific examples of how investment decisions were changed to prompt a reduction in frequency of outages in priority to reducing the duration of outages.

b) Approximately what percentage of Hydro One's transmission revenue requirement is paid directly by the direct connect customers that responded to the customer engagement survey process?
   i. What insight does Hydro One have with regard to the question of whether direct connect customers prefer scenarios with higher reliability and cost outcomes compared to the preferences of the average Ontario electricity consumer? Please provide details.

Response:

a) To mitigate risks to reliability, Hydro One can adopt a prevent, minimize or restore approach, whereby 'prevent actions' can prevent/reduce the frequency of outages while 'minimize and restore actions' reduce the duration of outages. Hydro One adopted an approach targeted to prevent outages and improve reliability performance through system renewal investments. Examples of outage prevention actions are included under the "Performance Improvement" and "Coordinated Asset Renewal" headings in Table 1 of Exhibit B, Tab 1, Schedule 1, Section 3.2.

b) The survey was anonymous. Hydro One did not provide Innovative with customer revenue information and has not considered customer revenue in its review of the customer engagement survey.

   i. Illustrative investment scenarios were posed to the transmission connected customers who chose to complete the survey. The distribution of how these customers indicated their preferred balance between rates and outcomes is captured in Exhibit B-1-1, Section 1.3, Attachment 1, page 47. We do not have comparable information/data related the average Ontario electricity consumers' preferred balance between rates and outcomes.

OEB INTERROGATORY #41

Reference:

TSP-01-03, TSP-01-03-01, TSP-01-03-04
(1) p.8
(2) Attachment 1, pp. 44-47
(3) Attachment 1, p.116
(4) Attachment 4, pp. 1-2

Interrogatory:

At the first reference above, Hydro One stated the following:

The key messages and results received by Hydro One from the 2017 Transmission Customer Engagement Survey are as follows:

- When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in the Prior Proceeding by at least a three to one margin. It is seen as reflective of the current approach which has served the system well, and a less risky option;

At the third reference above, Hydro One stated the following:

You will note that the two middle scenarios, B and C, offer a relatively small change in reliability risk, but moving from B to C offers significant improvements in long-term reliability. The key difference between B and C is that B has larger future increases, while C has level future rate increases. The big differences in reliability are in scenarios A and D. Moving from A to B creates a significant decline in reliability risk. Moving from scenario C to D generates both a long term reliability benefit and targeted reliability improvements for a small group of customers.

At the fourth reference above, Hydro One stated the following:

In its Decision in Hydro One's last Transmission Rate Application (EB-2016-0160) the Ontario Energy Board ("OEB") found that the model1 needs further refinement and testing if it is to be used to convey to customers information about the value of capital

[1] Reliability Risk Model

investments in terms of system reliability. A third party assessment completed by Metsco Energy Solutions Inc. has led to a similar conclusion and recommendations as discussed in TSP Section 1.4, section 1.4.2.14.

a) What was Hydro One customers' weighted-average preference (on a scale of 1 to 17) of the investment scenarios?

b) For each of the Scenarios A, B, C and D, how did Hydro One precisely quantify for the survey respondents that "[t]he key difference between B and C is that B has larger future increases, while C has level future rate increases"?
   i. Did Hydro One develop any example rate datasets to illustrate key differences between scenarios? Please provide examples that were presented to customers.

c) For each of the Scenarios A, B, C and D, how did Hydro One precisely quantify for the survey respondents that "[t]he big differences in reliability are in scenarios A and D. Moving from A to B creates a significant decline in reliability risk. Moving from scenario C to D generates both a long term reliability benefit and targeted reliability improvements for a small group of customers."?
   i. Did Hydro One develop any example reliability datasets to illustrate the differences between scenarios? Please provide examples that were presented to customers.

d) What efforts has Hydro One undertaken to determine how sensitive HONI customers are to the marginal trade-offs between costs and performance (e.g. reliability or power quality)?

e) Did Hydro One populate the Reliability Risk estimates in the above table using the Hydro One Reliability Risk Model?
   i. If yes, did Hydro One advise the customers answering the survey that "the Ontario Energy Board found that the model needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. A third party assessment completed by Metsco Energy Solutions Inc. has led to a similar conclusion and recommendations"?

Response:

a) Hydro One customers' weighted-average preference of the investment scenarios is 9.98.

b) The illustrative capital scenarios included both near term reinvestment options and those which would be paced out beyond the TSP period. The pacing of scenarios was directional in nature beyond the TSP period; no rate schedules were created for periods beyond the TSP period.

c) The Reliability Risk Model was used to communicate directional risk to customers and stakeholders. Please refer to Exhibit B, Tab 1, Schedule 1, Section 1.3, pages 114 to 115 for details on the scenarios presented.

d) Hydro One has not undertaken this sensitivity analysis.

e) Yes, the Reliability Risk Model was used. No, the customer engagement process was conducted prior the issuance of the OEB decision; the feedback from the OEB and subsequent METSCO report had not yet been received.

OEB INTERROGATORY #42

Reference:
TSP-01-03 p. 10-11
Figure 3

Interrogatory:
At the above noted reference, Hydro One stated the following:

Figure 3 illustrates the trend of the overall satisfaction results. In 2018, Overall Satisfaction was at the highest point in the past seven years at 90%, which is a 12% increase since 2016. The increase in overall satisfaction can be attributed to LDCs and generation customers. The main driver identified through analysis for higher customer satisfaction was customer communication and key account managers. The identified driver correlated with lower satisfaction was the ability to recall a planned outage.

a) Please explain what is meant by “The identified driver correlated with lower satisfaction was the ability to recall a planned outage.”
   i. Should this sentence refer to “unplanned outages” as opposed to planned outages?

b) Please confirm that Hydro One’s Customer Satisfaction metrics show no statistically significant correlation with:
   i. Any cost measure/metric.
   ii. Any reliability measure/metric, aside from the “recall of an unplanned outage”.

c) Given that customer communications and key account managers have a statistically significant impact upon customer satisfaction metric, are there any cost saving measures that Hydro One could implement to reduce the cost of its customer interaction process?

d) Does Hydro One use the Customer Satisfaction metric to justify any CAPEX projects included in this filing?

Response:
a) A regression analysis was completed by Innovative to determine if there was a correlation between overall satisfaction and other questions asked in the survey. If there was a correlation then this was deemed to be a driver of satisfaction.

i. Yes. This sentence should refer to unplanned outages.

b)

i. The survey does not explore cost other than one environmental control question that can be found in Exhibit B-1-1, TSP Section 1.3, Attachment 5, page 23. This question was not correlated to overall satisfaction.

ii. Confirmed. The only correlated driver is the recall of an unplanned outage. All correlated drivers can be found in Exhibit B-1-1, TSP Section 1.3, Attachment 5, page 26.

c) Key Account Management reviews its costs and considers cost saving opportunities on an annual basis. Recently the Account Executives were reassigned from customer-groups into geographic regions to better serve customers, and reduce on travel.

d) No.

OEB INTERROGATORY #43

Reference:
TSP-01-03 p. 28-33
Appendix 2 and EB-2016-0160 Decision and Order Revised: November 1, 2017, p. 24

Interrogatory:
At the first reference above, Hydro One described how it incorporated feedback from the OEB's previous transmission rate decision in the area of customer engagement into its customer engagement activities for the present application.

At the second reference above, one of the areas in which improvements could be made is stated as follows:

The process should be started sufficiently in advance of filing the application to allow for timely input to be incorporated in a meaningful way and to improve the level of customer attendance.

a) Please provide some examples as to how the input received from the customer engagement process undertaken for this application was incorporated into it in a meaningful way.

b) Please state the level of customer attendance for the customer engagement process for the preceding application and for the current one on a comparable basis.

Response:
a) The customer engagement process was started sufficiently in advance of the preparations of the transmission system plan included in this application:
    a. The draft report was received in June 2017, with a final report received in July 2017; the transmission system plan was prepared in 2018.
    b. The timing allowed for the identification of key themes and the associated development of investments to address those themes, including:
        - Concerns expressed with delivery point performance as a result of nuisance wildlife or equipment configuration;

- Coordination of asset maintenance and replacement activities with generator customers during planned outages to minimize disruptions to operations;
- Concerns expressed with power quality; and
- Addressing worst performing delivery points (outliers).

A listing of key investments which respond to specific customer needs and preferences is included in Exhibit B, Tab 1, Schedule 1, Section 3.2.

b) For the 2016 Customer Engagement, 12 customers participated in one-on-one dedicated meetings; 22 customers attended facilitated group sessions; 28 customers participated in the on-line consultation tool.

For the 2017 Customer Engagement, 102 customers participated on-line and one (1) customer completed the survey in-person.

OEB INTERROGATORY #44

Issue from Draft List:
[Issue Group]

Reference:
TSP-01-03 p. 28-33
Appendix 2 and EB-2016-0160 Decision and Order Revised: November 1, 2017, p. 24

Interrogatory:
At the second reference above, which is the previous transmission decision, one of the areas in which improvements could be made is stated as follows:

The information presented to the customers should be unambiguous and easy to understand.

At the first reference above, Hydro One described how it incorporated feedback from the OEB's previous transmission rate decision in the area of customer engagement into its customer engagement activities for the present application. Hydro One stated that with respect to ensuring that information presented to customers is easy to understand, the following had been done:

Finally, the design of the 2017 engagement survey included information that was purposefully written to ensure the content was unambiguous, sufficiently informative for customers to respond to, and easy for customers to understand. To gauge the quality and clarity of the information, the survey included a post-survey question asking "Did Hydro One provide too much information, not enough or just the right amount?" The result was that 76% of respondents believed the survey contained just the right amount of information.

a) Please explain why Hydro One believes that the views of customers on the amount of information presented would also be reflective of their views on the information being unambiguous and easy to understand.

<u>Response:</u>

a) Concerns with respect to the information provided to customers throughout the engagement were raised by stakeholders in advance of the Board's decision, and were taken into consideration in the design of the survey. The survey also sought customer feedback on the survey itself which can be found in Exhibit B-1-1, TSP Section 1.3, Attachment 1, pages 58-63. The question related to the "volume of information" was determined to be an easy to understand question that could elicit customer concerns, if any, about the amount and complexity of the information provided. Hydro One's interpretation of the Innovative survey does not reveal insights that would suggest the information was ambiguous or difficult to understand.

OEB INTERROGATORY #45

Reference:
TSP-01-04 p. 6 & 10

Interrogatory:
At the first reference above, Hydro One stated the following:

The benchmarking and other studies described below demonstrate that Hydro One's practices and processes for managing its key transmission assets are aligned with industry best practices. In two areas; underground cables and overhead conductor, the study results recommended Hydro One increase its expected service life ("ESL") for these assets. Hydro One will review its management practices and decision making procedures to minimize life-cycle costs and more effectively manage risk for these assets based on these recommendations. However, as asset replacements in Hydro One's business plan are selected based on end of life of the asset, this has not impacted the current business plan.

At the second reference above, Hydro One stated the following:

The results of this study based on current condition assessment data and historical overhead conductor replacement data, indicate that ESL for overhead conductors in the Hydro One transmission system should be approximately 90 years. Hydro One's assigned ESL for overhead conductors was set at 70 years before this study. The new ESL resulting from this study does not affect the current business plan as identified replacements are not age based decisions, they are based on verified asset condition.

a) Please describe the quantified relationship (if any exists) between Expected Service Life (ESL) and End of Life (EOL) for different asset classes or types.

b) Does the quantified relationship between ESL and EOL change for different asset classes or types of assets? If yes, please explain these differences.

c) Does the selected ESL for any of Hydro One's asset classes have any impact on Hydro One's determination of EOL for any assets within any of those classes (e.g. for conductors)?

d) Is ESL used to forecast longer-term conductor replacement requirements, or something else?

e) Does EOL change depending on the consequence of failure of specific assets in the same asset class?

<u>Response:</u>

a) Hydro One uses the Expected Service Life ("ESL") of assets as a general guideline to inform investment decisions. The ESL is defined as the average time duration in years that an asset can be expected to operate under normal system conditions and is determined by considering manufacturer guidelines and Hydro One's historical asset retirement data. Assets operating beyond ESL generally have a higher likelihood of failing or being in poor condition.

The term End of Life ("EOL") is also used and is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Therefore, while assets may be operating beyond ESL they may not be at EOL. At the same time, as the primary driver of replacement decisions, asset condition will be verified prior to the work being undertaken.

In general, an asset is expected to reach EOL at its ESL. In terms of a quantifiable relationship, the ESL is the average time an asset is expected to operate before reaching EOL. However, assets may reach EOL before or after their ESL (which should be considered as an average life expectancy). As the primary driver of replacement decisions, asset condition will be verified prior to work being undertaken.

b) Please refer to a) which is applicable for all assets.

c) EOL replacement is primarily driven by condition not ESL. Other criteria such as condition, historical performance, technology obsolescence, safety and reliability also play a role in justifying equipment replacement.

d) Conductor replacement is based on condition. ESL is used to help anticipate potential replacement quantities in the longer-term.

e) The consequence of failure is used to develop EOL assessment criteria. An asset is identified as being at EOL when the failure would cause unacceptable consequences. EOL criteria will not change for individual assets of the same asset class.

OEB INTERROGATORY #46

Reference:
TSP-01-04 p. 7

Interrogatory:
At the above noted reference, Hydro One stated the following:

Metsco reviewed the Reliability Risk Model ("RRM") and found that the analytical underpinnings and functionalities of the RRM trail advanced industry system reliability practices where used in asset management. In making this observation, Metsco found that a number of utilities do not nor have not until recently attempted to formally forecast system reliability in a comprehensive manner and suggests the RRM as a customer communications tool to convey directional changes to reliability risk levels across spend scenarios, Metsco is of the view that the observed gaps pose no meaningful risks from an asset planning perspective. Hydro One must remain clear about the tool's purpose and the implications of its analysis.

a) Do the observed gaps identify the risk of mis-characterizing the confidence that specific reliability outcomes would be produced by selecting different capital expenditure scenarios for the purpose of communicating with customers?

b) Do Hydro One's ARA and AA processes produce dependable forecasts of future reliability performance based upon the different capital investment scenarios being evaluated? In other words, is the proposed capital spending envelope optimized with respect to a quantified expectation of system reliability performance?
   i. If yes, please provide the expected system reliability results for the different spending scenarios considered in the planning efforts that informed the capital spending proposed in this application.
   ii. If no, please explain how the proposed spending levels were optimized.

Response:
a) Application of the RRM and future use of reliability forecasting models is detailed in TSP Section 1.3, Attachment 4. The reliability risk model was introduced by Hydro One in 2016 to provide a simplified method to communicate risk to customers and stakeholders. It is not used to identify specific asset needs or justify investments.

Asset needs are anchored by asset condition assessments and investments are justified by asset needs and prioritized in accordance with Hydro One's investment planning approach described in TSP Section 2.1, Investment Planning Process.

b) Investments are prioritized and optimized through Hydro One's Investment Planning Process across three categories: Safety, Reliability, and Environment.

   i. N/A
   ii. Investments are prioritized and optimized based on risk-spend efficiency, seeking opportunities to maximize risk mitigation within a capital envelope, with trade-offs to address non-risk considerations. Please refer to Exhibit B-1-1 TSP Section 2.1.

OEB INTERROGATORY #47

Reference:
TSP-01-04 p. 8

Interrogatory:
At the above noted reference, Hydro One stated the following:

More particularly, 80.5% of the asset condition assessments for Hydro One's transmission transformer fleet aligned with EPRI's PTX analysis based on dissolved gas in oil content and oil quality data. For the remaining 19.5% of assessments, the results of which were not well aligned, the majority of the differences are attributed to data issues such as oil cross contamination between tap changer and main tank oil.

a) Is Hydro One able to do anything to mitigate these data issues?

b) If yes, is Hydro One doing anything to mitigate them?

Response:
a) Yes.

b) The reason for this misalignment is mainly due to:
- Correct data that does not reflect the true condition of transformer when considering the historical trend or the design and configuration of the unit. Subject matter experts will interpret the data and decide the appropriate course of action.
- Incorrect data due to data entry or collection error. This data is corrected manually once noticed. Furthermore, Hydro One began a project to automatically populate transformer oil test results, received from laboratories, into our database system to mitigate data entry or collection errors. This project is now in the test stage and will be completed by the end of 2019.

OEB INTERROGATORY #48

Reference:

TSP-01-04 p. 10

Interrogatory:

At the above noted reference, Hydro One stated the following:

Hydro One's volume of replacement over the plan period is higher primarily due replacement criteria that were not included in the EPRI report. These criteria include obsolescence concerns, safety concerns (e.g. lack of or insufficient arc resistance rating), change in system conditions (e.g. short circuit level), polychlorinated biphenyl ("PCB") mitigation per regulatory requirements and integrated investments.

a) Please quantify the departure from the EPRI expected levels of volume replacement in terms of:
   - number of breakers;
   - percentage of fleet; and
   - Total replacement cost.

Response:

a)

- Number of breakers: EPRI’s recommendation was 491 units versus Hydro One’s planned 638 units. The difference is 147 breakers.
- Percentage of fleet: 13.4% (638/4774)
- Total replacement cost for 634 breakers: Hydro One employs an integrated approach to station asset replacement. Breaker replacements are included in the costs for the following ISDs: SR-01, 02, 03, 04, 05, 06 and 08.

OEB INTERROGATORY #49

Reference:
TSP-01-04 p. 11

Interrogatory:
At the above noted reference, Hydro One stated the following:

The majority of utilities have a formal process and algorithm for assessing transformer condition with 75% of these utilities use a risk-based approach with condition and system criticality ranking highest for their algorithm inputs. Like Hydro One, most utilities do not allow the algorithm to trigger a replacement but also rely on the input of subject matter expert assessments.

a) Does this mean that the algorithm alone cannot trigger a replacement, or that the algorithm in no way affects the selection of potential replacement candidates? Please explain in detail.

Response:
a) The algorithm alone cannot trigger a replacement. The decision to replace a transformer is subject to an asset needs assessment discussed in Exhibit B-1-1 TSP Section 2.1. The algorithm provides planners with an initial list of assets presenting potential operational risks.

OEB INTERROGATORY #50

Reference:
TSP-01-04 p. 12

Interrogatory:
At the above noted reference, Hydro One stated the following:

Hydro One's protective relay fleet consists of three technologies: electromechanical, solid state, and microprocessor. Electromechanical relays have the longest ESL and have a very reliable performance. At the time of the report, solid state relays account for 58% of all relays currently operating beyond ESL, which is a risk to safety and reliability as shown in TSP Section 2.2.1.3.

a) Has Hydro One improved its relay specification and selection process to ensure that future widespread adoption and implementation of new relay technologies does not produce similarly poor outcomes? If yes, please explain what has changed.

b) Based on the long ESL and very reliable performance of electromechanical relays, is Hydro One considering returning to broader application of such relays going forward? If not, explain why not.

c) Has Hydro One evaluated the different life cycle costs to ratepayers of using electomechanical, solid state and microprocessor relays?
   i. If yes, please provide those results.
   ii. If no, explain why not.

Response:
a) Hydro One’s relay technical specification is up-to-date in accordance with a number of standards from relevant organizations such as the Canadian Standards Association (CSA), Institute of Electrical and Electronic Engineers (IEEE) and International Electro-technical Commission (IEC).

b) No, electromechanical relay technology is obsolete.

c) Electromechanical and solid-state relay technologies are obsolete and no longer supported or developed by manufacturers. For this reason, Hydro One has not carried out extensive lifecycle cost analysis comparison between these technologies.

OEB INTERROGATORY #51

Reference:
TSP-01-04 p. 13

Interrogatory:
At the above noted reference, Hydro One stated the following:

EPRI has determined due to the current loading on Hydro One's low-pressure and high-pressure liquid-filled (LPLF and HPLF) cables that the suitable ESL should be increased to 70 years. Hydro One has previously been using 50 years as the ESL for these assets. The ESL is not used to trigger replacement. Replacement is triggered by asset condition.

a) Is the described extension of ESL reflected in reduced underground cable replacement program costs in the present application? If no, please explain why not.

Response:
a) The ESL extension did not result in a program increase or reduction since all underground cable replacement projects discussed in this application are initiated based on asset condition.

Witness: Donna Jablonsky

OEB INTERROGATORY #52

Reference:
TSP-01-04 p. 16

Interrogatory:
At the above noted reference, Hydro One stated the following:

This study confirms that the majority of Southern Ontario falls under the C4 corrosion rate category, with small pockets of C5 corrosion rate zones. The resolution of the atmospheric corrosion map has been refined with more defined boundaries between the various corrosion zones. This information enables Hydro One to use the higher resolution of the Ontario Atmospheric Corrosion Rate Map to optimize the tower coating program and to maximize the steel tower lifecycle. Hydro One accepts EPRI's recommendation to use the updated Ontario Atmospheric Corrosion Map to make more accurate decisions about the degradation of steel structures throughout the province. Hydro One plans to address these recommendations by overlaying the updated atmospheric corrosion map with existing Hydro One Geographic Information System ("GIS") data, in order to more accurately assign corrosion zones to each structure.

a) Please provide a table correlating the tower re-coating projects proposed in this application with the Ontario Atmospheric Corrosion Map zones.

b) Please provide a map overlaying the tower re-coating projects proposed in this application onto the Ontario Atmospheric Corrosion Map.

c) Has EPRI's recommendation to use the updated Ontario Atmospheric Corrosion Map to make more accurate decisions about the degradation of steel structures throughout the province been applied in this application?
   i. If not, why not?
   ii. If yes, did doing so increase or decrease the annual planned re-coating investment levels over the plan period?

Response:

a) Planning for the tower coating program occurs on a yearly basis. The planned work for 2020 is as shown in the table below. Note that half units refer to partially coated towers from previous years, which are scheduled to be completed.

Zone	Circuit	Line Section	C4 Corrosion Zone	C5 Corrosion Zone	Grand Total
Niagara	R19th	**ERINDALE JCT-CHURCHILL MEADOWS CTS**	4.5		4.5
	R19th	**RICHVIEW TS-TOMKEN JCT**	0.5		0.5
Niagara Total			**5.0**		**5.0**
East	L1S	**SUDBURY JCT-MARTINDALE TS**	0.5		0.5
	T31H	**MARINE JCT-OSHAWA NORTH JCT**	15.5	17.0	32.5
	T32H	**HAVELOCK TS - OSHAWA NORTH JCT**	59.5	4.5	64.0
East Total			**75.5**	**21.5**	**97.0**
Sarnia	L24L	**LAMBTON TS #2-LAMBTON JCT**		7.5	7.5
	L26L	**LAMBTON TS #2-LAMBTON JCT**		7.0	7.0
	D4W	**Detweiler TS - Kitchener MTS**	9.5		9.5
	W44LC	**BUCHANAN TS-COWAL JCT**		102.5	102.5
	D4W	**Kitchen MTS 9 - Buchanan TS**	11.5		11.5
	L24L	**LAMBTON JCT-MACKSVILLE JCT**		17.5	17.5
Sarnia Total			**21.0**	**134.5**	**155.5**
Grand Total			**101.5**	**156.0**	**257.5**

b) Please refer to a) which provides the Ontario Atmospheric Corrosion Zones for projects proposed in 2020.

Witness: Donna Jablonsky

c) Yes, it has helped to prioritize the investment.

ii. The annual planned re-coating levels did not change due to the EPRI study. The pacing is consistent with Hydro One's plan in ISD-SR-22.

OEB INTERROGATORY #53

Reference:
TSP-01-04 p. 17

Interrogatory:
At the above noted reference, Hydro One stated the following:

Other types of 230 kV insulators should continue to be assessed periodically for signs and degrees of degradation. EPRI further recommends that linemen should check the integrity of these insulators prior to performing any live maintenance procedures due to potential safety issues. Considering the study results, Hydro One will prioritize the removal of specific polymer insulators in its current replacement program.

a) Please quantify the number of insulators affected by the described premature deterioration and the cost to replace all at-risk insulators.

b) Please categorize the priority of replacement by manufacturer, voltage, absence of corona rings and any other parameters Hydro One considers germane to the replacement program.

c) Has Hydro One modified its specification, procurement and design processes to ensure that similar polymer insulator issues are avoided in future widespread new technology implementations?
   i. If yes, please provide details.
   ii. If no, please explain why not.

Response:
a) Hydro One is planning to identify the number of 230kV insulators affected by the described premature deterioration and anticipates to have this completed in 2020. Until then, it is not possible to quantify the cost to replace all at-risk insulators.

b) The following factors are considered:
   - 230kV Polymers on dead-end structures
   - 230kV Polymers on suspension structures with no corona ring
   - 230kV Polymers on suspension structures with 4in (or smaller) corona rings

The above apply to the following manufacturers:

- K-Line
- NGK
- Ohio Brass

Similar to Hydro One's existing COB/CP insulator replacement program, priority will consider: public accessibility, proximity to major infrastructure, and circuit criticality.

c) Hydro One no longer purchases polymer insulators for transmission lines unless prompted by special circumstances. For such cases, specifications have been updated to reflect new electric field limits (i.e. when corona rings are required).

OEB INTERROGATORY #54

Reference:
TSP-01-04 p. 21

Interrogatory:
At the above noted reference, Hydro One stated the following:

Hazard curve function analysis suggests that the removal rate in Region 2 is largely due to discretionary removal (planned replacement).

a) This key finding was identified for both the derivation of transmission substation transformer hazard functions and for Circuit Breaker hazard functions. Please quantify the delta between EPRI removal rate and Hydro One removal rate, in number of units, percentage of fleet and total cost of replacement for both the substation transformers and circuit breakers.

Response:
Transformers
- The unit difference between EPRI's transformer removal rate (max. 66 units) and Hydro One's planned removal rate (63 units) during the 2020 to 2022 period is 3 units.
- The percentage of the fleet would be ~0.4% (3/721).[1]
- The cost difference would depend on the proposed transformer replacement candidates.

Breaker
- The unit difference between EPRI's circuit breaker removal rate (max. 295) and Hydro One's planned removal rate (328 units) during the 2020 to 2022 period is 33 units.
- The percentage of the fleet would be ~0.7% (33/4774) of the fleet.
- The cost difference would depend on the proposed circuit breaker replacement candidates.

[1] 721 is the total count of transformers at the time when the report was written.

Witness: Donna Jablonsky

OEB INTERROGATORY #55

Reference:

TSP-01-04 p. 22

Interrogatory:

At the above noted reference, Hydro One stated that "Half of utilities refurbish transformers to extend life."

a) Does Hydro One refurbish transformers to extend life?
   i. If yes, please provide documented examples of refurbishment vs. retirement decisions.
   ii. If no, please explain why not.

b) If one exists, please provide the formula used by Hydro One to establish refurbishment investment limits, driven solely by estimated remaining service life (defined as ESL minus actual age).
   i. Once an asset has exceeded ESL, what is the maximum allowed refurbishment investment?

Response:

a) No, power transformers are refurbished to preserve their expected service life and reliability, not to extend their life.

b) Hydro One employs a model that provides the Present Value for three options: maintain status quo, refurbish, or replace. It uses several factors such as maintenance cost, replacement cost, tax capital cost allowance, and the discount rate. Please refer to Interrogatory I-01-OEB-19 Attachment 1 for an example.
   i. There is no set value and the maximum allowed refurbishment cost will depend on the evaluated asset.

OEB INTERROGATORY #56

Reference:

TSP-01-04 p. 23
Table 8

Interrogatory:

a) For Key Finding #1:
   i. What are the primary factors that cause concern at 44 years?
   ii. Are the factors of concern different for different types of breakers (e.g.: bulk oil, minimum oil, ABCB and SF6)?
   iii. If yes, does the 44 year "concern" threshold still apply across all breaker types?

b) For Key Finding #2, how are 1/3 of respondents able to run transmission breakers to fail, while the others do not? Is run-to-fail seen as a prudent operating approach for those respondents?

Response:

a)
   i. Condition and safety are the two highest ranked criteria for replacing a breaker. Please refer to Exhibit B-1-1 TSP Section 1.4 Attachment 6 page 64.
   ii. EPRI does not specify it but Hydro One expects the factors of concern for breakers to be similar in terms of demographics, but every type of breaker will have different factors. Please refer to Exhibit B-1-1 TSP Section 1.4 Attachment 8 and 9 which describes different factors related to different breaker types.
   iii. No. Please refer to Exhibit B-1-1 TSP Section 1.4 Attachment 6 page 63-64.

b) The EPRI survey did not investigate how 1/3 of the respondents are able to run their breakers to failure. However the report found that the majority of utilities do not have a formal process or algorithm for assessing circuit breaker condition.” It is possible that many respondents run their breakers to failure because they lack the process and resources to proactively address deterioration and foreseeable failure. Hydro One does not view run to failure as a prudent approach as it would elevate safety and system risk.

Witness: Donna Jablonsky

OEB INTERROGATORY #57

Reference:
TSP-01-04
Table 16

Interrogatory:

a) For Key Finding #1:
   i. Is there an economically practical way to refurbish deteriorated housings to extend the replacement program over a longer period?
   ii. Is Hydro One retrofitting non-deteriorated K-Line insulators with larger corona rings to mitigate this issue?
   iii. How many Hydro One insulators are affected by this type fault?

b) For Key Finding #2:
   i. Why were these insulators installed without corona rings?
   ii. Did Hydro One follow the manufacturer's recommended installation practice, or did Hydro One customize the installation design?
   iii. Should these premature failures be characterized as a type fault or a design deficiency?
   iv. How many Hydro One insulators are affected by this issue?

c) For Key Finding #3, how many Hydro One insulators are affected by this type fault?

d) For Key Finding #4, is Hydro One actively implementing this recommendation? If no, why not?

e) For Key Finding #8:
   i. Is the statement true regardless of manufacturer?
   ii. What percentage of silicone insulators have been damaged?
   iii. How many insulators does this represent?

Response:

a) For Key Findings #1:
   i. There is no practical way to refurbish the rubber housing of the insulators. This damage is irreversible and the housing cannot be replaced.

ii. These insulators have been in service for over 20 years but have an estimated service life of 30 years; therefore it is not economical to retrofit these insulators with larger corona rings nor would it extend the remaining service life.

iii. Hydro One is planning to identify the number of 230kV insulators affected by the described premature deterioration and anticipates to have this completed in 2020.

b) For Key Findings #2:

i. At the time of installation, it was an industry standard to install 230kV polymer insulators without a corona ring.

ii. Hydro One adhered to the manufacturers' guidelines and did not customize installations.

iii. These premature failures could be categorized as a design deficiency. However at the time, the industry was not aware of the extent of the damage the electric field would cause the rubber housing without an adequate corona ring.

iv. Please refer to part a) iii.

c) Please refer to part a) iii.

d) No. This recommendation is technically valid but not economical. These insulators have been in service for over 20 years but have an estimated service life of 30 years. Adding a new corona ring will not extend the remaining service life nor reverse damage.

e) For Key Finding #8:

i. Correct. This statement applies to polymeric material in general and therefore applies to all manufacturers.

ii. It is not possible to know the percentage of insulators damaged by excessive electric fields. What we deduce, as per the EPRI findings, is that polymer insulators with 4in or smaller corona rings are considered at-risk and need to be removed from the system as soon as practically possible.

iii. Please refer to part a) iii.

OEB INTERROGATORY #58

Reference:
TSP-01-04 p. 32

Interrogatory:
At the above noted reference, Hydro One stated the following:

Increased outcome definition: In 2017, Hydro One was able to translate the results of its investment plan into expected customer outcomes with greater specificity than it had in previous years, leading to 5 year targets for key scorecard metrics.

a) Does "greater specificity" as used here mean "greater precision", "greater accuracy", and/or "higher confidence"? Please explain.

Response:
a) Greater specificity refers to more specific outcome performance; previously outcomes may have been positioned as directional, such as maintain reliability performance, whereas now a specific outcome target is identified, as included in the Evolved Transmission Scorecard (Exhibit B-1-1 TSP Section 1.5).

OEB INTERROGATORY #59

Reference:

TSP-01-04-01 p. 27

Figure 3-7

Interrogatory:

a) Is the high ratio of Canadian Westinghouse (CW) transformers with abnormal values primarily driven by vintages, manufacturing defects, both factors, or other factors? Please specify.

Response:

a) Most of the CW units with “abnormal” flag are 230 kV units and were manufactured between 1966 and 1976. Vintage does impact the deterioration of the insulation particularly for heavily loaded units. This process is irreversible.

OEB INTERROGATORY #60

Reference:
TSP-01-04-02 p. 17
Figure 1-2

Interrogatory:
At the above noted reference, EPRI stated the following:

Figure 1-2 shows the age demographics of the removed from service transformers from the period of 1981 to first quarter 2017.

a) Does Figure 1-2 show all transformers removed from service for all causes, including actual failures, imminent failures, and discretionary retirements such as preventative replacements, replacements to increase capacity, and all other causes?
   i. If no, please describe what is displayed in Figure 1-2.

b) Is Hydro One able to categorize replacements by all different causes over this period?
   i. If yes, please provide this categorization.

c) Hydro One's policies have historically not allowed for refurbishment investments to be made in transformers that have exceeded their expected service lives, even if the required refurbishments would be relatively low cost. Is that still Hydro One policy? For example, would a transformer operating beyond its expected service life qualify for replacement of leaking bushing gaskets, or replacement of worn tap changer components?

Response:
a) Yes.

b) No. For replacements prior to 2006 the reason for removal is not generally available.

c) Yes. Power transformers are refurbished to preserve their expected service life and reliability, not to extend their life. The decision to refurbish vs. replace a transformer is subject to the results from a technical and financial assessment.

Witness: Donna Jablonsky

OEB INTERROGATORY #61

Reference:

TSP-01-04-02 p. 18
Figure 1-3

Interrogatory:

a) Figure 1-3 appears to show a lack of correlation between transformer age and likelihood of failure. Please explain these results.

Response:

a) Figure 1-3 shows the age demographics of the failed transformers from the period of 2006 to fourth quarter 2016. This figure cannot be used to establish a correlation between transformer age and likelihood of failure because:
   i. Some failures are considered "pre-mature" failures due to manufacturing defects. This explains the one unit that failed after one year in service; and
   ii. The expected service life for each category of power transformer is different and this value varies between 40 to 60 years: please refer to Exhibit B-1-1 TSP Section 2.2 Table 3. Figure 1-3 presented all transformer categories in one chart.

OEB INTERROGATORY #62

Reference:

TSP-01-04-02 p. 21 & 25TSP-01-04-03 p. 21

Interrogatory:

At the first reference above, EPRI stated the following:

However, removed from service data is more abundant and consist of 419 transformers within a period of 1981 to first quarter 2017. The reasons for removal are not supplied in data, therefore failures and discretionary replacements cannot be distinguished. Since the reason is not supplied a time-to-event model can be developed where the event, rather than failure, is removal.

At the second reference above, EPRI stated the following:

Fitting the data to the Model

The removal rate model is verified by comparing the sample cumulative hazard function calculated from the actual event data (previously described) against the cumulative hazard functions created from the Weibull model. There are cumulative hazard functions for each MCMC observation. For each age from 0 to 100, we calculate the median cumulative hazard rate and the corresponding 95% credibility interval.

At the third reference above, EPRI stated the following:

Removed from Service Data

The removed from service data provided by Hydro One consists of 1218 circuit breakers as of third quarter 2017. No reason for removal was provided.

a) Please confirm that the term “removals” is not synonymous with the term “failures”.

b) Removals are being used to create a “hazard” curve, even though the reasons for the removals have not been categorized. Is this methodology appropriate as EPRI is applying it here?

c) A true "Hazard Rate" implies an age-related likelihood of failure. Please confirm that the supplied input data does not support the determination of a true Hazard Rate for these assets.

d) Based on the above references, it appears that EPRI has used uncategorized asset removal data in its derivation of Hazard Rates because that was the data set provided by Hydro One, rather than because the data is fit for purpose. Does the lack of categorization of retirement causes in the data supplied to EPRI potentially invalidate the conclusions drawn in the both the "Derivation of Circuit Breaker Hazard Functions" report and the "Derivation of Transmission Substation Transformer Hazard Functions" report?

Response:

a) Confirmed. The term “removals” is not synonymous with the term “failures”, it includes but not limited to “failures”.

b) It is appropriate as EPRI employed a mathematical representation (Weibull model) to filter out the impact of non-failure replacements data. This is shown in Exhibit B-1-1 TSP Section 1.4 Attachment 3 Figure 2-2 and Exhibit B-1-1 TSP Section 1.4 Attachment 2 Figure 2-4.

c) Confirmed, the supplied data included both failure and non-failure related data. Although non-failure related data does not support the determination of a true hazard curve, the mathematical method used in the report was able to eliminate the impact of non-failure related data; thus making it a true hazard rate.

d) No, please see b) above.

OEB INTERROGATORY #63

Reference:

TSP-01-04-04 p. 22

Interrogatory:

At the above noted reference, EPRI stated the following:

Conductor Condition Assessment Data

The Hydro One Conductor Condition Assessment Program defines an overall condition score of as equivalent to "end-of-life." Hydro One provided condition assessment data collected between January 2001 and December 2016.

Investigators separated conductor assessment data by Overall Condition Score (OCS). Of the initial 404 conductor samples, 28 samples were assessed as OCS 5 from 21 different circuits and 61 samples were assessed as OCS 4 from an additional 29 different circuits. The remaining 315 samples were assessed as OCS 1 through 3.

a) Were the samples randomly gathered, or were they gathered from facilities with conductors previously identified as being near end of life? Please describe the sample gathering process applied.

Response:

a) The majority of conductor samples were taken from the set of the oldest conductor spans in the system that had yet to be assessed. A smaller set of samples came from conductors that were tested to be in Good or Fair Risk condition in the past, to maintain visibility on the progression of their deterioration. As per Exhibit B-1-1, TSP Section 2.2, Page 56 of 117, 20.8% of the transmission conductor fleet has yet to receive condition assessment.

Witness: Donna Jablonsky

OEB INTERROGATORY #64

Reference:

TSP-01-04-04 p. 27

Interrogatory:

At the above noted reference, EPRI stated the following:

Correlation of Overall Condition with Age

The following three figures examine the relationships between overall condition and age; the third slide showing a histogram of conductor count by age between two overall condition groups (1-4 vs. 5). From these figures it may be observed that there is not a simple relationship between age and overall condition.

a) Would it not be more accurate to state that "there is not an *apparent* relationship between age and overall condition"? Most of the conductors around 100 years of age are all in condition 1 or 2.

b) Please confirm that the first chart in Figure 3-1 does not show a compelling age-related trend.

c) Does data scarcity outside of the core demographic distribution range potentially compromise the statistical confidence of any analysis drawing upon those outliers?

Response:

a) No, the number of samples assessed from each age group must be considered. As outlined Exhibit B-1-1, TSP Section 1.4, Attachment 4, pages 81-98, EPRI was able to relate age to condition using Weibull distribution modeling.

b) This figure does not make this conclusion – it simply showcases the condition density by age, as per the available samples.

c) No, as concluded in Exhibit B-1-1, TSP Section 1.4, Attachment 4, pages 97, the Weibull models were able to provide "a fairly accurate description of past conductor performance as a function of age".

Witness: Donna Jablonsky

OEB INTERROGATORY #65

Reference:
TSP-01-04-04 p. 29-32

Interrogatory:
At the first reference above, EPRI stated the following:

Extent and Severity of Rust
Figure 3-4 shows the extent of rust by age, as determined by visual inspection. Figure 3-5 shows severity of rust by age. From these two figures it may be observed that rust assessments do not appear to be reliable or useful assessment factors, possibly due to the subjective nature of visual inspection.

At the second reference above, EPRI stated the following:

Rust Assessments vs. Corrosion Zone
Investigators expected to see the best of rust ratings (e.g. 1, 2) skew towards corrosion zone C2 and C3, whereas the worst of the rust ratings (e.g. 5 or even 4) skew towards corrosion zone C5. However, such a pattern is not immediately apparent from the plots in Figure 3-10.

a) Were any of the conductor replacements in Hydro One's previous filing primarily driven by assumed age or location based corrosion issues?

b) Are any conductor replacements planned for the test period based upon assumed age or location based corrosion issues? If yes, please reconcile this justification against the referenced observations.

Response:
a) According to our records, all conductor replacements in the previous filing, as well as this filing, are driven by verified condition and not age or location.

b) No planned conductor replacement is based upon assumed age or location. As noted by EPRI in the referenced report, no clear correlation between corrosion zone and conductor condition was found, and therefore all planned conductor replacements are driven by empirically verified condition.

OEB INTERROGATORY #66

Reference:
TSP-01-04-04 p. 95

Interrogatory:
At the above noted reference, EPRI stated the following:

The conductor Condition Assessment (Score) data used are not from random samples. For the replacements data, it is unclear whether all replacements were due to failures or lines reaching condition(s) that warrant replacements or some other reasons. Analysis results from such data can potentially be pessimistic. However, the similarity between results based on condition assessment data and results based on replacements data lead one to believe that such a concern is not necessarily warranted, especially when the commonalities between the two data, sources in terms of time periods and circuits represented are limited (as discussed previously and shown in Figure 4-3).

a) Please confirm the following is an appropriate interpretation of the above paragraph:
   i. The data set is not representative of the general conductor population.
   ii. This assessment could lead to pessimistic results.
   iii. EPRI is not able to confirm whether or not the identified data deficiency is problematic.

b) Could the potential for pessimistic results identified in this statement drive excessive capital spending on conductor replacements?

Response:
a)
   i. No, as shown through the correlation assessments in chapter 3 of Exhibit B-1-1, TSP Section 1.4, Attachment 4, samples are diverse in age, conductor size and condition.
   ii. No, the referenced statement above by EPRI stated "the similarity between results based on condition assessment data and results based on replacements data lead one to believe that such a concern is not necessarily warranted".
   iii. No, in Exhibit B-1-1, TSP Section 1.4, Attachment 4, Page 97 of 98 EPRI stated: "The good agreement between the two EPRI Weibull models derived from

> "failed" condition assessment data and historical replacements suggests that these models provide a fairly accurate description of past conductor performance as a function of age."

b) As per Exhibit B-1-1, TSP Section 1.4, Attachment 4, Page 97 of 98, EPRI believes a fairly accurate description of past conductor performance as a function of age can be made from the findings in this report. All planned conductor replacements are driven by verified condition.

OEB INTERROGATORY #67

Reference:
TSP-01-04-11 p. 11

Interrogatory:
At the above noted reference, EPRI stated the following:

Hydro One removed a total of 87 polymer insulators for analysis. The samples were removed from lattice and from wood pole structures.
It was recognized that locations with significant wetting or contamination would be the optimum environment from which the insulators should be removed. Based upon that, most of the insulators were removed from circuits in Southern Ontario.

a) Were these samples randomly selected, or chosen from locations with known insulator deterioration problems? Please provide details of the sample selection process.

Response:
a) The insulator samples were randomly selected from various locations in Southern Ontario. The reason for that is because Southern Ontario experiences more rainfall and is consequently more susceptible to corona discharge activity. Testing insulators at these locations would therefore provide the best understanding of the overall polymeric population.

OEB INTERROGATORY #68

Reference:
TSP-01-04-13 p. 30 TSP-02-01 p. 36 & 37

Interrogatory:
At the first reference above, Metsco stated the following:

Such an expression of risk (or risk costs) is considered to be an asset management best practice since it captures both likelihood and consequence of failure in a single numerical value – making prioritization across individual assets, asset classes, or intervention options both simpler and more transparent.

At the second reference above, Hydro One stated the following:

As part of its improved assessment process, Hydro One has introduced a new "flagging" process to account for special considerations and ensure stakeholder perspectives are consistently included in the evaluation of investments. Investment considerations that cannot be quantified using the risk framework described above are captures by using qualitative flags to allow consideration of potential benefits of an investment beyond risk mitigation. To incorporate key customer and regulatory outcomes into its evaluation of projects, Hydro One's flags enable it to identify investments that address key customer priorities such as improving power quality, and investments that align to strategic priorities and objectives.

a) Given that asset management best practice is to quantify risk calculations in order to make "prioritization across individual assets, asset classes, or intervention options both simpler and more transparent", please explain why the use of non-mandatory flags is necessary and Hydro One is not able to achieve asset management best practice for each of the following flags:
    i. Customer Engagement
    ii. Productivity
    iii. Corrective Maintenance / Demand Replacements
    iv. Preventative Maintenance / System Renewals
    v. Strategic
    vi. Political Commitments

b) Given that asset management best practice is to make "prioritization across individual assets, asset classes, or intervention options both simpler and more transparent", for each of the non-mandatory flags please answer the following

   i. Why is a business case (or equivalent) not used to evaluate the application of a Customer Engagement flag? Please provide an example of the typical documentation supporting the application of a typical Customer Engagement flag.

   ii. Why is a business case (or equivalent) not used to evaluate the application of a Productivity flag? Please provide an example of the typical documentation supporting the application of a typical Productivity flag.

   iii. Please provide an example of the typical documentation justifying the application of a typical Strategic flag.

      1. In addition, please provide the process whereby codified goals by the leadership team or an explicit request by senior leadership is converted into investment spending outside of the standard Asset Management evaluation process.
      2. In addition, how is the investment limit for the Hydro One leadership team determined for a Strategic flag?

   iv. Why is a business case (or equivalent) not used to evaluate the application of a Customer Engagement flag? Please provide an example of the typical documentation supporting the application of a typical Political Commitments flag.

      1. In addition, please provide the Hydro One governing the policy of a Hydro-One officer's power to make political commitments.
      2. In addition, how is the investment limit for a Hydro One officer determined for a Political Commitments flag?

c) Is there any potential that projects where significant 'productivity' can be achieved may leapfrog projects that would otherwise be prioritized higher due to more urgent need or higher risk?

   i. If yes, does that potentially subvert the intention of the asset management process?

   ii. If yes, how does Hydro One mitigate this problem?

<u>Response:</u>

a) Hydro One achieves asset management best practice using a prioritization methodology based on risk mitigation in the categories of safety, reliability and environment, and a comparison across asset classes.

Historically, Hydro One's risk taxonomies included quantitative risk factors such as safety, reliability, and environment, and more qualitative factors such as customer satisfaction, government relations, and brand. These more qualitative risk factors reflected real risks to the business, however were subject to much discussion and varied interpretation. As a result, Hydro One rationalized its risk factors, and introduced additional non-mandatory flags which would supplement the risk assessment. The revised risk scoring process includes applying qualitative flags that allow consideration of other potential benefits of an investment beyond risk mitigation. Hydro One has implemented controls, in the form of calibration and challenge sessions, to provide assurance that qualitative flags are applied consistently and that Hydro One's values and objectives are being addressed.

Generally, investments subject to the non-mandatory flags are also risk scored against safety, reliability and environment taxonomies, however for those investments that are considered marginal, the consideration of a non-mandatory flag adds additional context for trade-off discussions. A description of the flags is included in Exhibit B, Tab 1, Schedule 1, Section 2.1, page 38.

b) Please see below:

i. Generally, investments subject to the customer engagement flag are also risk scored against safety, reliability and environment taxonomies as the basis for prioritization. A business case is prepared prior to execution approval. A summary example of the application of a customer engagement flag is: Bruce B SS Refurbishment: Replacement of Air Blast Circuit Breakers (ABCBs) will be aligned with Bruce Power refurbishment project.

ii. Generally, investments subject to the productivity flag are also risk scored against safety, reliability and environment taxonomies as the basis for prioritization. A summary example of the application of a customer engagement flag is: OM&A-Transmission Rights of Way – Grounds and Sites: Embedded savings and cost reductions as a result of contracted services through Brookfield Global Integrated Solutions.

iii. OM&A - Emergency Response Plans: This program supports the Journey to Zero Initiative, ensuring Emergency Response Plans reflect up to date emergency procedures and up to date contact information, consistent with the Health, Safety and Environment Emergency Preparedness and Response Procedure.

1. There is no process where by investments are identified outside of the standard asset management evaluation process. Please refer to Figure 9 of Exhibit B, Tab 1, Schedule 1, Section 1.1; strategic investments would be identified through the "Business Objectives and Strategies" stream, followed by a review and validation of the need. Should the need be validated, a candidate investment for consideration would be developed and prioritized consistent with the investment planning process.
2. There is no formalized limit; investments with the strategic flag are subject to the investment prioritization and review process described in Exhibit B, Tab 1, Schedule 1, Section 2.1.

iv. Generally, investments subject to the customer engagement flag are also risk scored against safety, reliability and environment taxonomies as the basis for prioritization. A business case is prepared prior to execution approval.

Generally, investments subject to the political flag are also risk scored against safety, reliability and environment taxonomies as the basis for prioritization. A summary example of the application of a political flag is: SA-04: Metrolinx Traction Substations: Connection of Metrolinx traction power substations supports Provincial GO Regional Express Rail Initiative and electrification of GO rail corridors.

1. There is no governing policy.
2. There is no formalized limit for investment planning purposes, and investment allocation is subject to the investment planning and prioritization process.

c) Yes, there is potential for trade-offs to occur between "productivity" investments and investments which may mitigate more risk.

i. No, the asset management process reflects risks and opportunities which respond to the needs and preferences of a broad group of stakeholders, including customers that have indicated cost as a consideration.

ii. As part of the investment planning and prioritization process, Hydro One reviews investments from both a risk-efficiency perspective as well as an absolute risk mitigation perspective as a control against significant risks being left unmitigated.

OEB INTERROGATORY #69

Reference:
TSP-01-04-13 p. 9, 10 & 17

Interrogatory:
At the first reference above, METSCO stated the following:

With respect to the Reliability Risk Model, METSCO's finding is that the tool's analytical underpinnings and functionalities trail advanced industry system reliability practices where these are deployed in the asset management. In making this observation, we note that a number of utilities do not or have not until recently attempted to formally forecast system reliability in a comprehensive manner. This contextual observation suggests that the RRM capability constitutes a bona fide continuous improvement step. Given that the RRM tool is currently used primarily as a customer communications tool to convey indicative changes to reliability risk levels across spend scenarios, the observed gaps in its technical parameters pose no meaningful risks from the asset planning perspective.

Notwithstanding these findings, potential improvements to the RRM capability (or another reliability forecasting capability that Hydro One may choose to procure) that METSCO recommends in this report, would enhance its practical applicability and robustness, should Hydro One decide to integrate the tool as part of the asset management decision-making process more broadly.

At the second reference above with respect to Figure 1, METSCO stated the following:

Our assessment of the Reliability Risk Model does not extend beyond this first level of assessment. The rationale for this decision is primarily grounded in the limited extent to which it is integrated Hydro One's asset management processes

a) Please confirm that Hydro One agrees with the statement that Hydro One's reliability analytic tool's "analytical underpinnings and functionalities trail advanced industry system reliability practices where these are deployed in the asset management".

b) Please confirm that Hydro One agrees with the statement that “the RRM tool is currently used primarily as a customer communications tool”.
   i. If not, what it is primarily used for?

c) Please confirm that Hydro One agrees with the statement that enhancing Hydro One’s “RRM capability … that METSCO recommends in this report, would enhance its practical applicability and robustness, should Hydro One decide to integrate the tool as part of the asset management decision-making process more broadly.”

d) Please confirm that Hydro One agrees with the statement that the Reliability Risk Model is limited in the “extent to which it is integrated Hydro One’s asset management processes”

e) What is Hydro One’s plan (expressed in terms of scope, schedule and budget by year) to close the observed analytic tool gaps (i.e. RRM gaps) to enable incorporation of quantified expected system reliability outcomes into Hydro One’s asset management decision-making processes?

Response:

a) As noted in Exhibit B-1-1 TSP Section 1.3, Attachment 4, Hydro One is aware of reliability forecasting models, however comprehensive assessment and testing of these models is not complete.

b) Confirmed, the RRM is a simplified method to communicate risk to customers.

c) To date, use of the RRM is solely used to communicate outcomes regarding various investment scenarios to customers; at this stage, Hydro One is not contemplating any further integration of the tool as part of the asset management decision-making process. Asset needs are anchored by asset condition assessments and investments are justified by asset needs and prioritized through Hydro One’s investment planning process, described in Exhibit B-1-1 TSP Section 2.1.

d) Confirmed, please refer to part b) above.

e) As noted in Exhibit B-1-1 TSP Section 1.3, Attachment 4, Hydro One will continue to explore and assess other reliability forecasting models to quantify the outcome of its investment plan in the future.

Witness: Bruno Jesus

OEB INTERROGATORY #70

Reference:

TSP-01-04-13 p. 25-26

Interrogatory:

At the above noted reference, METSCO stated the following:

Recalling that one of the categories of our Level 1 assessment of these two capabilities is the degree of flexibility applied to analysis of various asset classes, our Level 2 assessment reviews the AA and ARA frameworks from the perspective of six major asset classes that undergo analysis by these two frameworks. These asset classes are:

- Power Transformers
- Circuit Breakers
- Protection, Control & Telecom Infrastructure
- Station Ancillary Equipment
- Overhead Transmission Conductors
- Underground Transmission Cables

a) Please confirm that Towers and Poles are included in the analysis performed within the AA and ARA frameworks.
    i. If so, why didn't METSCO evaluate the frameworks for these major asset classes?
    ii. If not, why doesn't Hydro One evaluate these major asset classes using the AA and ARA frameworks
    iii. Does Hydro One evaluate these classes outside of the AA and ARA frameworks?

Response:

a) Yes, towers and poles are included in the analysis performed within the AA and ARA frameworks.
    i. The scope of this study was limited to the 6 major asset classes noted above. These 6 classes encompass high value assets which represent a major portion of Hydro One's transmission investments.
    ii. Please refer to i.

iii. Hydro One primarily evaluates these asset classes using AA and ARA, but occasionally may rely on other information sources to determine condition status.

OEB INTERROGATORY #71

Reference:
TSP-01-04-13 p. 25-26

Interrogatory:
At the above noted reference, METSCO stated the following:

The outputs of the AA process are a Composite Risk Score and a framework of individual analytical parameter Risk Score Sub-Indices, ranging from zero (lowest risk) to 100 (highest risk). These scores are derived for each individual asset. The sub-indices represent the following assessment sub-categories:

- Condition: considers the data on the physical state of assets and their core components along the relevant degradation factors expected to compromise the overall condition of an asset. Condition data used in the index development is sourced from field inspections, as well as Preventative Maintenance, Defect, and Trouble Call Reports, as relevant.

- Demographics: Takes into consideration the assets' physical age in relation to its projected service life value or "Expected Service Life" (ESL), along with other demographic criteria like type, batch, manufacturer, etc. Hydro One defines asset ESL as the "average time duration in years that an asset can be expected to operate under normal system conditions and is determined by considering manufacturer guidelines and Hydro One historical asset retirement data." The ESL criteria for particular asset classes were derived from the results of a 2014 Asset Failure Analysis study conducted by Foster Associates, in which asset class specific failure curves were validated using Hydro One's own historical failure data, and Iowa curve functions [3].

- Criticality: Takes into consideration the impact of failure at the individual asset, asset class, and station levels respectively. Input information for the formulation of this index includes factors like total customer load, voltage rating, critical customers and interconnections related to a given asset.

- Performance: Considers historical performance of a given asset, including the historical outage frequency and duration, as well as results from a Laplace trend test, which provide a measure of the difference in interval time between multiple forced outages.

- Utilization: provides the measure of asset deterioration related to the increased rate of asset utilization. Inputs such as the summer and winter peak loads, tap changer counter readings, and unit capacity data are used to formulate the index in this category for each asset.

- Economics: Takes into consideration the weighted average of emergency and corrective costs required to maintain the existing asset, as compared to the benchmark cost for the specific asset type/class.

Each of the AA evaluation category sub-indices, along with the overall composite score, contain references to “risk-based” calculations, incorporating parameters related to “probability” and/or “impact” of asset failure.

a) Please provide the source document for reference [3] above (i.e. R.E. White, “2014 Asset Failure Analysis”, Foster Associates, 2014).

b) Please describe how the Risk Score Sub-Indices are used to calculate the Composite Risk Score.

c) For each of the assessment sub-categories, please define if the assessment sub-categories are used to inform the determination of Probability of Failure Only, Impact (i.e. Consequence) of Failure Only, Both Probability and Impact of Failure, or Neither Probability nor Impact (i.e. Consequence) of Failure.

d) For assessment sub-categories that are used to inform the determination of Probability of Failure, please define quantitatively how they work together to determine Probability of Failure.

e) For assessment sub-categories that are used to inform the determination of Consequence of Failure, please define quantitatively how they work together to determine Consequence of Failure.

f) Please define how Criticality is measured or otherwise determined for an asset failure.

g) Please confirm the range of Composite Risk Score for Power Transformers, Circuit Breakers, Protection, Control & Telecom Infrastructure, Station Ancillary Equipment, Overhead Transmission Conductors, Underground Transmission Cables, and if applicable, Towers and Poles.

h) Please confirm that a Risk Score Sub-Indices ranges from zero (lowest risk) to 100 (highest risk).

Response:

a) This report was filed in EB-2016-0160 responding to OEB Staff's interrogatory I-1-20. Please see Attachment 1.

b) The composite risk score is a weighted score of the sub-indices.

c) The sub-categories are not used to directly inform the probability nor the consequence of failure.

d) Please refer to c) above.

e) Please refer to c) above.

f) Criticality quantifies the impact of an individual asset to the system.

g) The range is 0 to 100.

h) Confirmed, it ranges between 0 and 100.

2014 Asset Failure Analysis

foster associates

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Ronald E. White, Ph.D.
Chairman

August 19, 2014

Mr. Bruno Jesus
Manager Asset Strategies
HYDRO ONE NETWORKS INC.
483 Bay Street, 14th Floor
Toronto, ON M5G 2P5

RE: <u>2014 Asset Failure Analysis</u>

Dear Mr. Jesus:

Foster Associates is pleased to submit our report of a 2014 Asset Failure Analysis for Hydro One Networks Inc. This report presents the results of our analysis of physical and inspection failures observed in selected plant categories using the Iowa curve family to validate studies conducted by Hydro One using the Weibull statistical distribution function.

Section I provides an overview of our investigation and a discussion of the statistical techniques employed in the analysis. The principal findings are summarized in Section II including a description of the data sets analyzed, the recorded failures over the observation period, the full band censoring, Weibull parameters estimated by Hydro One and the projection life and Iowa curve Foster Associates would select based solely on a consideration of the statistical analysis conducted for each data set. Section III contains the actuarial service life analysis for each data set as described in Section I.

We wish to express our appreciation for the opportunity to again be of service to Hydro One and for the able assistance and cooperation provided by your staff. We would be pleased to discuss the study with you or others at your convenience.

Respectfully submitted,
FOSTER ASSOCIATES, INC.
by

Ronald E. White, Ph.D.
Chairman

REW:ml

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August 2014

Executive Summary

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a 2014 statistical analysis of physical and inspection failures observed in selected plant categories classified in Transmission Lines, Transmission Stations and Distribution Lines owned and operated by Hydro One Networks Inc. (Company or Hydro One). Foster Associates was requested by the Company to conduct the analysis using the Iowa curve family to validate studies conducted by Hydro One using the Weibull statistical distribution function.

Physical failures are defined as the removal of plant no longer providing intended services. Causes of physical failures with near immediate removal include deterioration, wear and tear, actions of the elements, accidents and obsolescence. Inspection failures (*e.g.*, distribution wood poles) are defined as plant tagged for eventual physical removal and/or replacement by failing to pass service criteria inspections.

It is important to emphasize that this study does not provide a prediction of the mean or expected age of future failures. The investigation provides a mathematical description of forces of failure observed in the past and an estimate of the mean age of reported failures. This distinction is often described by a two–step procedure for estimating the mortality characteristics of a plant category. The first step (called *life analysis*) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* descriptive of the parent population from which a plant category is viewed as a random sample.

The second step (called *life estimation*) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the population exposed to retirement. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future. The scope of the current investigation was limited to a life analysis of the subject properties.

THE WEIBULL DISTRIBUTION AND THE IOWA CURVE FAMILY

The Weibull distribution function is prominent in the statistical analysis of asset lives because of its versatility in modeling various modalities of asset failure and its ability to replicate other distributions such as the Negative Exponential, the Rayleigh, or the normal distribution. The function's three–parameter definition offers an unlimited set of estimation possibilities. That advantage, however, is offset by the lack of a simplified classification of parameters to model common sets of service life scenarios such as that available in the Iowa Curve family.

Developed at Iowa State University, the Iowa curve family is a set of 31 distributions defined by the location of the mode relative to the mean (left, center, and right of the mean, depicted as L, S, and R respectively) and the height of the mode. This classification and finite set of distributions offers the Iowa curve family a level of usability unavailable with other statistical functions such as the Weibull distribution. Although a more detailed discussion of the Iowa curve family and the Weibull distribution function is beyond the scope of this report, it has been shown that the Weibull distribution offers an acceptable approximation to the Iowa curve family and that there exists a bounded range of values of the Weibull shape parameter which should be considered in such approximations.[1]

ANALYSIS

Thirty–two data sets were initially provided to Foster Associates by Hydro One. Twenty–nine of the data sets included physical failures and age distributions of survivors at December 31, 2013. Two of the remaining three data sets (*i.e.*, Transmission Steel Structures, and Transmission Wood Poles) included age distributions of surviving plant and physical failures identified only by age and not by vintage year of placement.[2] The remaining data set (*i.e.* Distribution Wood Poles) contained inspection failures and age distributions of survivors at December 31, 2013. Five of the thirty–two physical failure data sets were combined with related sets to provide a more consistent comparison with the Weibull distribution analysis conducted by Hydro One in 2010. This report, therefore, contains an analysis of twenty–seven data sets and one additional set subsequently provided to identify physical failures of distribution poles rather than pole inspection failures.

Distribution pole inspection failures reported by Hydro One were obtained from inspections conducted in six geographical regions using a six–year cycle such that every pole is inspected at least once in six years. A failure through inspection is defined as a pole "not satisfying full service criteria." This definition of failure does not mean that a pole is retired from service. Nor does the data provided include pole retirements from non–inspection events such as storms, accidents, road construction, and normal pole failure unrelated to that observed during inspections. Accordingly, an inspection failure means that the pole is a candidate for physical retirement which could occur at a later date. The measured "service life" statistic for inspection failure, therefore, is the average age at which a pole is considered a candidate for retirement.

Further discussion with Hydro One concerning the desirability of obtaining a statistic descriptive of Distribution wood pole physical failures resulted in Hydro

[1]Kateregga, Kimbugwe A., "Equipment Lives", M.Sc. Thesis, University College of Swansea, University of Wales, 1981.

[2]Data provided subsequently by Hydro One identified the vintage year of placement and permitted all data sets to be analyzed similarly.

One providing Foster Associates data on physical removals. The available information, however, was limited to the age distribution of survivors at mid–year 2011 and mid–year 2014. Foster Associates used the two age distributions to derive implied physical failures distributed evenly among the three years.

The conventional treatment of plant additions and retirements in conducting a statistical analysis of physical property is to assume that such activity occurs at the mid–point of a calendar year (*i.e.*, July 1). Using this so–called "half–year convention" required that 2011 survivors be positioned at December 31, 2011 and retirements at mid–year 2012, 2013 and 2014. The bias, if any, introduced by this assumption would be ± six months added to a mean service life estimated in years. Any bias introduced by the half–year convention, however, would be small in relation to the assumed uniform distribution of retirements within the three–year interval between 2011 and 2014.

The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each failure or retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study for the 29 data sets for which vintaged physical failures were initially available.[3] The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio (called a "retirement ratio") is an estimator of the hazard rate or conditional probability of retirement during an age interval given survival to the beginning of the age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

Construction of life tables for the three data sets for which vintage identifica-

[3]Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State University Engineering Research Institute Bulletin 125, revised edition. 1967, p. 27.

tion of retirements was not initially provided was achieved using the individual–unit method.[4] The data consisted of the age (in years) and the number of property units retired at each age. The number of property units surviving at each consecutive age was obtained from a reverse cumulative summation of the retirements, assuming the oldest retirement was recorded in 2013. The earliest vintage year was derived as the difference between 2013 and the age of the oldest retirement. The individual–unit method produces a single vintage with zero censoring that can be analyzed using the same statistical techniques as applied to a life table constructed from the annual–rate method.[5]

After conducting a preliminary analysis of the three accounts using the individual–unit method, Hydro One collected additional data to identify vintage years and permit application of the annual–rate method. Vintaged transactions were subsequently provided to allow observed life tables to be constructed for all twenty–seven data sets using the annual–rate method.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios.[6] The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by an unweighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. A minimum sum of squares criterion is used to identify the "best fitting" Iowa curve.

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[4]*Ibid.* p. 19.

[5]A life table is considered *censored* when the observed proportion surviving in the last age interval is greater than zero percent. Statistical inferences drawn from heavily censored life tables are less meaningful than inferences drawn from lightly censored tables in which the observed proportion surviving is approaching zero percent.

[6]Weighting is used in the polynomial linear regression to address the non–constant variance of hazard rates over the span of observations. Although unweighted and other weighting schemes such as inverse of age or inverse of variance can be used, exposure weighting was used in this study to simplify an understanding of how the weight given to successive retirement ratios was reduced over increasing age–intervals. The weights constitute the diagonal of a weight matrix used in estimating the parameters of the assumed polynomial equation. R. A. Fisher's adaptation of the orthogonal polynomials of Tchebycheff was used to reduce the computational time in a multiple regression analysis. Coefficients of successively higher degree polynomials can be estimated without re–estimating the coefficients of each lower degree term.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band, and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life–analysis program developed by Foster Associates include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

A standard analysis using rolling, shrinking, and progressive bands was conducted for each data set. Underlying observed life tables were developed and analyzed using the proportion retired as the estimator of the hazard rates and exposures as weights. The scope of this engagement did not permit an extension of the analysis to alternative estimators of hazard rates such as the actuarial or maximum likelihood or to other weighting options such as inverse of age or inverse of variance.

SUMMARY AND RECOMMENDATIONS

The principal findings of the Hydro One Networks 2014 Asset Failure Analysis are summarized in Section II of this report. The section contains a table (page 9) showing a description of the data sets analyzed (Column A), the number of units surviving at December 31, 2013 (Column B), the recorded failures over the observation period (Column C), the full band censoring (Column D), Weibull parameters estimated by the Company in a 2010 analysis (Columns E, F, and G) and the projection life and Iowa curve (Column H) Foster Associates would select based solely on a consideration of the rolling band, shrinking band, progressive band, and graphical analysis conducted for each data set.

Actuarial service life analyses (Schedules A–E) are provided in Section III for each data set. Although a single observed life table, a single graphics analysis plot, and a single polynomial hazard function plot are provided, Foster Associates' selection was based upon an analysis of numerous trials and windows on the available data. The number of trials was dictated by the number of years in the observation band. The 1980–2013 observation band in the 115kV Breakers dataset, for example, yielded 30 five–year rolling bands, 17 two–year shrinking bands, and 17 two–year progressive bands. Each trial indicated a separate dispersion and average service life for the 1^{st}, 2^{nd}, and 3^{rd} degree polynomial graduations. In most cases, however, the selected parameters are reflective of the full band analysis.

As noted earlier, the 2014 Failure Analysis does not provide a prediction of the mean or expected age of future failures. The study was undertaken to compare service life indications derived using the Iowa curve family with indications derived by Hydro One using the Weibull survival function. Absent further investigation, it cannot be concluded that future forces of asset failures will be identical to those observed in the past or the response to such forces will be described by statistics derived from an analysis of historical failures. The scope of the current investigation was limited to a statistical *life analysis* without consideration of the elements of *life estimation.*

SECTION II

Analysis

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the Hydro One Networks Asset Failure Analysis. Supporting schedules include:

Schedule A – Observed Life Table;

Schedule B – Actuarial Life Analysis;

Schedule C – Graphics Analysis;

Schedule D – Polynomial Hazard Function; and

Schedule E – Selected Projection Life Curve;

The format and content of these schedules are briefly described below.

SCHEDULE A – OBSERVED LIFE TABLE

This schedule provides a tabulation of retirements, exposures, conditional proportion retired (retirement ratio), conditional proportion surviving (survivor ratio), and cumulative proportion surviving at consecutive ages for a selected placement and observation band. The conditional proportion retired is an estimator of the hazard rate for an age interval.

SCHEDULES B – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band (Schedule B1), shrinking–band (Schedule B2), or progressing–band (Schedule B3) analysis depending upon the movement of the end points of the band.

The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE C – GRAPHICS ANALYSIS
This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; and b) the statistically best fitting Iowa dispersions and respective average service lives derived from the 1st, 2nd and 3rd degree polynomial hazard functions. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed hazard rates are displayed in the title block of the displayed graph.

SCHEDULE D – POLYNOMIAL HAZARD FUNCTION
This schedule provides a plot of the observed hazard rates and the graduated 1st, 2nd and 3rd degree polynomial hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE E – ESTIMATED PROJECTION LIFE CURVE
This schedule provides a plot of the projection curve and projection life considered a reasonable descriptor of future forces of mortality in relation to the observed proportion surviving for a selected placement and observation band.

HYDRO ONE NETWORKS INC.
Comparative Summary
December 31, 2013

	Account Description	12/31/2013 Survivors	Observed Failures	Censoring (%)	2010 Weibull Parameters β	η	μ	Iowa Curve
	A	B	C	D	E	F	G	H
Distribution Lines								
DLDXPOLES1	Poles - Inspection Failures	1,455,349	64,987	55.1				100-S0
DLDXPOLES2	Poles - Physically Removed	1,438,512	53,542	22.6				57-SC
Transmission Lines								
TLOHLINES	Overhead Lines (in Meters)	21,854,370	3,072,283	43.6	11.6	87.4	83.7	88-S3
TLSTSTRCT	Steel Structures	48,548	588	97.2				100-R5
TLUGCABLE	Underground Cables (in Meters)	237,000	28,600	21.7	10.4	59.3	56.5	55-R4
TLWDPOLES	Wood Poles	36,395	9,089	48.8	13.5	63.1	60.7	90-S1
Transmission Stations								
TS050BRKX	50kV Breakers	2,607	1,022	19.3	5.1	56.0	50.3	53-R1.5
TS050CONA	50kV Conventional and Metalclad Air Breakers	285	163	0.0	8.1	59.5	55.9	47-S2
TS050CONO	50kV Conventional Oil Breakers	1,327	602	22.0	5.9	59.3	53.0	57-R2.5
TS050CONS	50kV Conventional and Metalclad SF6 Breakers	756	234	44.5	4.2	32.7	29.7	30-R3
TS050CONV	50kV Conventional and Metalclad Vacuum Breakers	239	23	37.3	7.6	23.0	20.8	25-R3
TS115BRKX	115kV Breakers	743	449	14.7	6.5	63.6	54.0	50-S1
TS115CONO	115kV Conventional Oil Breakers	307	381	18.2	7.6	64.4	56.3	56-L3
TS115CONS	115kV Conventional SF6 Breakers	436	68	2.4	5.0	37.1	34.0	25-R3
TS230BRKX	230kV Breakers	705	357	3.6	7.9	47.1	44.4	40-R2
TS230CONA	230kV Conventional Air Breakers	134	119	42.0	13.7	44.7	43.1	43-R4
TS230CONO	230kV Conventional Oil Breakers	182	146	4.3	7.1	50.7	47.5	46-L3
TS230CONS	230kV Conventional and GIS SF6 Breakers	389	92	53.4	1.6	73.9	25.7	42-L0
TS500BRKX	500kV Breakers	238	75	37.7	10.3	38.9	37.1	35-R1
TS500CONA	500kV Conventional Air Breakers	56	25	44.8	7.6	41.3	39.0	45-L2
TS500CONS	500kV Conventional and GIS SF6 Breakers	182	50	56.3	4.8	28.6	26.2	33-R1
TSAUTOTRN	Auto Transformers	151	39	54.3	4.6	58.2	53.2	75-L0
TSCAPACIT	Capacitors	349	77	32.2	2.2	27.2	24.0	45-L1
TSHVSDTRN	HV Stepdown Transformers	621	277	9.6	5.2	58.5	53.9	54-R1.5
TSLVSDTRN	LV Stepdown Transformers	6	5	28.6	10.2	63.0	60.0	45-L1
TSREACTOR	Reactors	509	49	0.0	2.6	42.6	35.5	35-R1
TSREGLTRN	Regulating Transformers	20	39	20.2	5.2	53.2	49.0	45-R3
TSSWITCHX	Switches	7,601	1,025	0.0	7.9	83.2	21.3	33-R0.5

SECTION III

Supporting Schedules

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

Placement Band: 1929 - 2013
Observation Band: 2005 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	94,834	282	0.00297	0.99703	1.00000
0.5	110,112	123	0.00112	0.99888	0.99703
1.5	122,016	112	0.00092	0.99908	0.99591
2.5	130,254	122	0.00094	0.99906	0.99500
3.5	135,120	242	0.00179	0.99821	0.99407
4.5	127,044	342	0.00269	0.99731	0.99229
5.5	130,791	562	0.00430	0.99570	0.98961
6.5	128,051	616	0.00481	0.99519	0.98536
7.5	122,531	636	0.00519	0.99481	0.98062
8.5	120,712	613	0.00508	0.99492	0.97553
9.5	116,019	830	0.00715	0.99285	0.97058
10.5	110,734	603	0.00545	0.99455	0.96364
11.5	109,421	280	0.00256	0.99744	0.95839
12.5	115,656	433	0.00374	0.99626	0.95594
13.5	128,336	357	0.00278	0.99722	0.95236
14.5	156,226	413	0.00264	0.99736	0.94971
15.5	172,420	525	0.00304	0.99696	0.94720
16.5	189,062	405	0.00214	0.99786	0.94431
17.5	214,311	311	0.00145	0.99855	0.94229
18.5	245,006	408	0.00167	0.99833	0.94092
19.5	268,734	673	0.00250	0.99750	0.93936
20.5	283,075	524	0.00185	0.99815	0.93700
21.5	277,948	556	0.00200	0.99800	0.93527
22.5	291,279	540	0.00185	0.99815	0.93340
23.5	273,197	650	0.00238	0.99762	0.93167
24.5	280,238	661	0.00236	0.99764	0.92945
25.5	275,017	715	0.00260	0.99740	0.92726
26.5	265,490	818	0.00308	0.99692	0.92485
27.5	244,796	810	0.00331	0.99669	0.92200
28.5	237,893	867	0.00364	0.99636	0.91895
29.5	237,995	957	0.00402	0.99598	0.91560
30.5	247,801	1,038	0.00419	0.99581	0.91192
31.5	235,029	1,097	0.00467	0.99533	0.90810
32.5	238,332	1,368	0.00574	0.99426	0.90386
33.5	223,837	1,261	0.00563	0.99437	0.89867
34.5	226,127	1,297	0.00574	0.99426	0.89361
35.5	218,164	1,094	0.00501	0.99499	0.88848

Schedule A

HYDRO ONE NETWORKS INC.
Distribution Lines
Account: DXPOLES1 Poles - Inspection Failures

Placement Band: 1929 - 2013
Observation Band: 2005 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	222,847	1,301	0.00584	0.99416	0.88403
37.5	216,681	1,366	0.00630	0.99370	0.87886
38.5	211,168	1,236	0.00585	0.99415	0.87332
39.5	206,634	1,161	0.00562	0.99438	0.86821
40.5	201,714	1,150	0.00570	0.99430	0.86333
41.5	188,512	1,204	0.00639	0.99361	0.85841
42.5	185,604	1,101	0.00593	0.99407	0.85293
43.5	176,688	1,186	0.00671	0.99329	0.84787
44.5	180,890	1,141	0.00631	0.99369	0.84218
45.5	177,082	1,380	0.00779	0.99221	0.83687
46.5	187,915	1,452	0.00773	0.99227	0.83035
47.5	192,585	1,396	0.00725	0.99275	0.82393
48.5	194,113	1,386	0.00714	0.99286	0.81796
49.5	209,489	1,562	0.00746	0.99254	0.81212
50.5	221,906	1,592	0.00717	0.99283	0.80606
51.5	229,771	1,491	0.00649	0.99351	0.80028
52.5	238,953	1,486	0.00622	0.99378	0.79509
53.5	251,971	1,850	0.00734	0.99266	0.79014
54.5	259,333	1,870	0.00721	0.99279	0.78434
55.5	268,762	1,951	0.00726	0.99274	0.77868
56.5	290,160	2,203	0.00759	0.99241	0.77303
57.5	272,566	2,049	0.00752	0.99248	0.76716
58.5	249,696	2,050	0.00821	0.99179	0.76139
59.5	228,166	1,578	0.00692	0.99308	0.75514
60.5	201,688	1,384	0.00686	0.99314	0.74992
61.5	175,804	1,284	0.00730	0.99270	0.74478
62.5	140,782	908	0.00645	0.99355	0.73934
63.5	112,029	569	0.00508	0.99492	0.73457
64.5	73,583	658	0.00894	0.99106	0.73084
65.5	25,962	148	0.00570	0.99430	0.72430
66.5	19,611	199	0.01015	0.98985	0.72017
67.5	9,816	176	0.01793	0.98207	0.71286
68.5	2,756	77	0.02794	0.97206	0.70008
69.5	2,600	43	0.01654	0.98346	0.68052
70.5	2,522	85	0.03370	0.96630	0.66927
71.5	2,430	21	0.00864	0.99136	0.64671
72.5	2,269	30	0.01322	0.98678	0.64112

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

Placement Band: 1929 - 2013
Observation Band: 2005 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	2,032	28	0.01378	0.98622	0.63265
74.5	1,397	8	0.00573	0.99427	0.62393
75.5	1,475	31	0.02102	0.97898	0.62036
76.5	1,248	29	0.02324	0.97676	0.60732
77.5	707	14	0.01980	0.98020	0.59321
78.5	299	7	0.02341	0.97659	0.58146
79.5	212	2	0.00943	0.99057	0.56785
80.5	178	2	0.01124	0.98876	0.56249
81.5	159	0	0.00000	1.00000	0.55617
82.5	145	0	0.00000	1.00000	0.55617
83.5	109	1	0.00917	0.99083	0.55617
84.5	0	0	0.00000	1.00000	0.55107

Schedule B1

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

T-Cut: None

Placement Band: 1929-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2005-2009	36.7	96.3	L1 *	6.42	93.8	L1.5	6.27	120.0	SC *	6.57
2006-2010	41.3	98.3	L1 *	5.86	96.5	L1.5	5.75	133.0	SC *	6.25
2007-2011	53.9	108.7	L1	3.74	106.0	L1	3.62	152.3	SC *	4.68
2008-2012	60.7	116.8	S0	3.07	109.1	S0	2.74	157.6	R0.5 *	3.85
2009-2013	62.0	117.0	S-.5	2.50	96.7	R1	1.50	146.4	SC *	1.98

Schedule B2

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

T-Cut: None
Placement Band: 1929-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2005-2013	55.1	106.7	L0.5	2.83	99.1	S0	2.39	144.6	SC *	3.34
2007-2013	56.7	109.5	S-.5	2.87	98.5	S0	2.28	145.4	SC *	3.16
2009-2013	62.0	117.0	S-.5	2.50	96.7	R1	1.50	146.4	SC *	1.98
2011-2013	64.4	127.4	SC	3.39	92.2	R1	2.04	140.1	SC *	1.89
2013-2013	40.6	102.8	O3	8.78	69.4	SC	5.78	108.7	O3 *	5.69

Schedule B3

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

T-Cut: None

Placement Band: 1929-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2005-2006	38.5	96.9	L1.5 *	5.31	91.5	S0.5	5.03	83.1	R2 *	4.61
2005-2008	35.2	95.5	L1 *	6.36	93.5	L1.5	6.25	92.0	L1.5 *	6.22
2005-2010	40.1	98.9	L1 *	5.98	97.0	L1.5	5.87	132.0	SC *	6.34
2005-2012	55.1	107.6	L1	3.07	106.8	L1	3.04	151.6	SC *	4.23
2005-2013	55.1	106.7	L0.5	2.83	99.1	S0	2.39	144.6	SC *	3.34

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

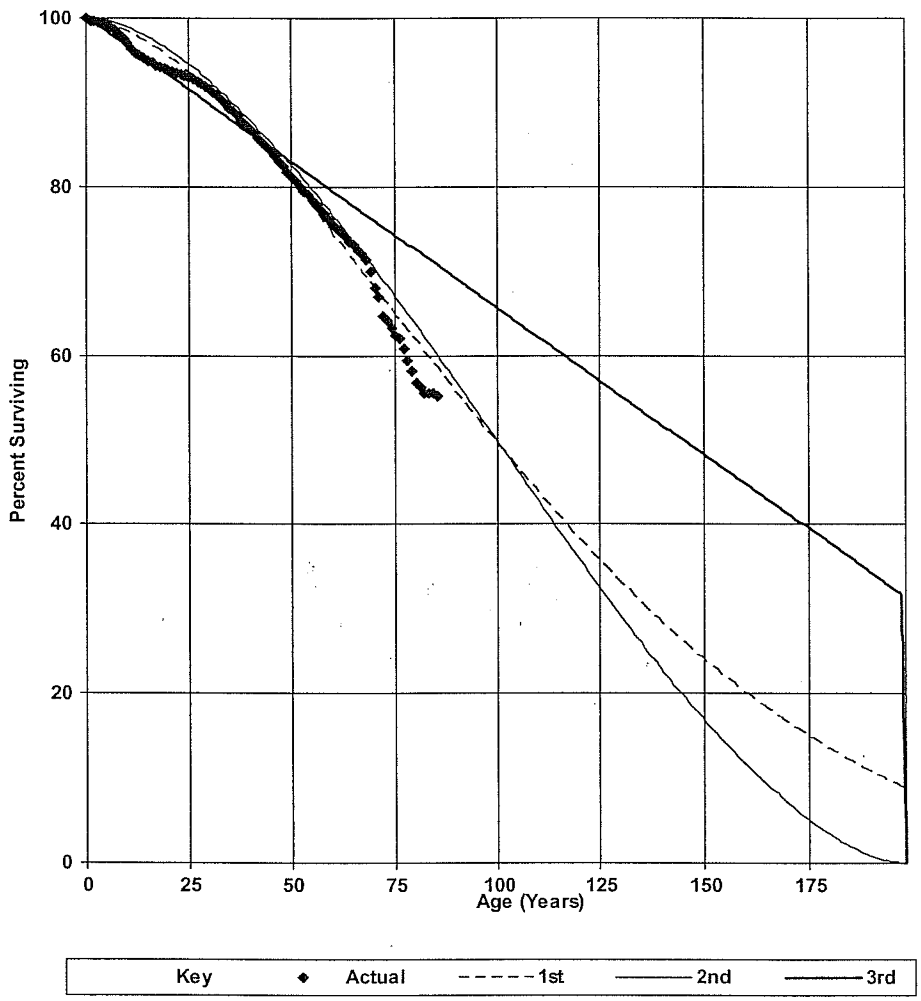
T-Cut: None

Placement Band: 1929-2013 Observation Band: 2005-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 106.7-L0.5 2nd: 99.1-S0 3rd: 144.6-SC



HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

T-Cut: None

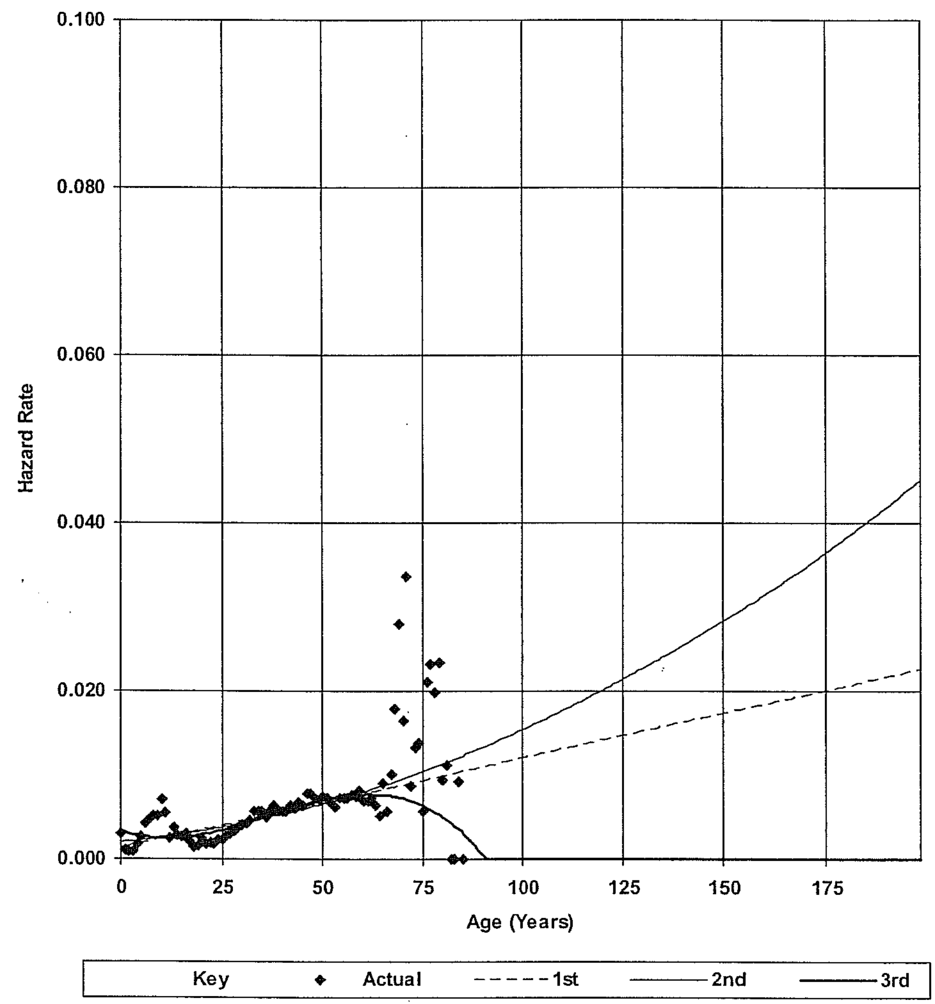
Placement Band: 1929-2013 Observation Band: 2005-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 106.7-L0.5 2nd: 99.1-S0 3rd: 144.6-SC



Schedule E

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES1 Poles - Inspection Failures

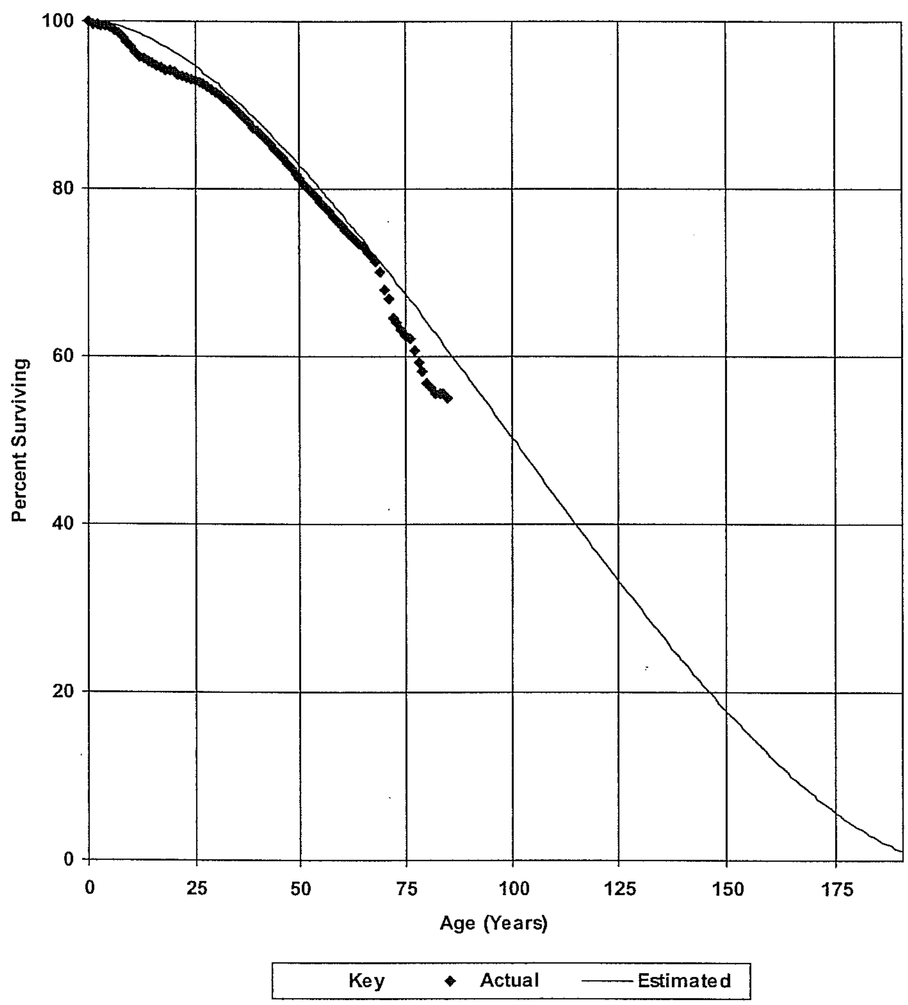
T-Cut: None

Placement Band: 1929-2013

Observation Band: 2005-2013

Estimated Projection Life Curve

100.0-S0



HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES2 Poles - Physically Removed

Placement Band: 1930 - 2011
Observation Band: 2012 - 2014

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	0	0	0.00000	1.00000	1.00000
0.5	2,338	12	0.00527	0.99473	1.00000
1.5	9,672	52	0.00541	0.99459	0.99473
2.5	23,879	135	0.00567	0.99433	0.98934
3.5	32,476	203	0.00625	0.99375	0.98374
4.5	39,440	396	0.01004	0.98996	0.97759
5.5	41,513	611	0.01473	0.98527	0.96777
6.5	42,061	832	0.01977	0.98023	0.95352
7.5	43,754	867	0.01982	0.98018	0.93467
8.5	41,753	762	0.01825	0.98175	0.91614
9.5	46,803	734	0.01568	0.98432	0.89942
10.5	46,094	778	0.01688	0.98312	0.88532
11.5	39,975	740	0.01851	0.98149	0.87038
12.5	37,040	663	0.01791	0.98209	0.85427
13.5	34,162	540	0.01582	0.98418	0.83897
14.5	36,749	583	0.01585	0.98414	0.82570
15.5	33,526	474	0.01415	0.98585	0.81261
16.5	32,680	344	0.01054	0.98946	0.80111
17.5	30,657	195	0.00637	0.99363	0.79267
18.5	35,467	211	0.00595	0.99405	0.78762
19.5	45,533	253	0.00556	0.99444	0.78293
20.5	58,458	330	0.00564	0.99436	0.77858
21.5	86,554	437	0.00505	0.99495	0.77418
22.5	93,469	502	0.00537	0.99463	0.77028
23.5	99,627	537	0.00539	0.99461	0.76614
24.5	92,536	562	0.00607	0.99393	0.76201
25.5	106,435	654	0.00614	0.99386	0.75738
26.5	111,375	661	0.00594	0.99406	0.75273
27.5	105,528	639	0.00605	0.99395	0.74826
28.5	79,823	477	0.00597	0.99403	0.74373
29.5	81,791	516	0.00631	0.99369	0.73929
30.5	77,484	502	0.00648	0.99352	0.73462
31.5	96,298	690	0.00717	0.99283	0.72986
32.5	83,672	679	0.00811	0.99189	0.72463
33.5	84,310	722	0.00856	0.99144	0.71875
34.5	70,491	645	0.00915	0.99085	0.71260
35.5	73,948	683	0.00924	0.99076	0.70608

Schedule A

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES2 Poles - Physically Removed

Placement Band: 1930 - 2011
Observation Band: 2012 - 2014

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	77,386	768	0.00992	0.99008	0.69956
37.5	81,424	830	0.01019	0.98981	0.69262
38.5	77,304	793	0.01025	0.98975	0.68556
39.5	76,240	801	0.01051	0.98949	0.67853
40.5	72,012	781	0.01084	0.98916	0.67140
41.5	75,250	935	0.01243	0.98757	0.66412
42.5	65,401	807	0.01233	0.98767	0.65587
43.5	70,345	888	0.01262	0.98738	0.64778
44.5	65,258	809	0.01240	0.98760	0.63960
45.5	70,713	920	0.01301	0.98699	0.63167
46.5	65,841	878	0.01334	0.98666	0.62345
47.5	62,817	872	0.01389	0.98611	0.61514
48.5	54,194	786	0.01450	0.98550	0.60659
49.5	50,996	710	0.01392	0.98608	0.59780
50.5	50,015	712	0.01423	0.98577	0.58947
51.5	57,224	830	0.01451	0.98549	0.58109
52.5	61,059	947	0.01551	0.98449	0.57265
53.5	75,705	1,192	0.01575	0.98425	0.56377
54.5	81,628	1,288	0.01578	0.98422	0.55490
55.5	82,023	1,287	0.01569	0.98431	0.54614
56.5	84,138	1,290	0.01533	0.98467	0.53757
57.5	83,399	1,203	0.01442	0.98558	0.52933
58.5	86,590	1,236	0.01428	0.98572	0.52170
59.5	79,755	1,069	0.01340	0.98660	0.51425
60.5	86,868	1,226	0.01412	0.98588	0.50735
61.5	89,826	1,293	0.01439	0.98561	0.50019
62.5	103,728	1,952	0.01882	0.98118	0.49299
63.5	118,315	2,518	0.02128	0.97872	0.48372
64.5	94,249	2,227	0.02363	0.97637	0.47342
65.5	65,370	1,405	0.02149	0.97851	0.46224
66.5	24,764	572	0.02311	0.97689	0.45230
67.5	18,421	442	0.02398	0.97602	0.44185
68.5	8,201	261	0.03179	0.96821	0.43126
69.5	714	15	0.02100	0.97900	0.41755
70.5	357	15	0.04290	0.95710	0.40878
71.5	461	17	0.03759	0.96241	0.39124
72.5	1,183	58	0.04904	0.95096	0.37653

Schedule A

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES2 Poles - Physically Removed

Placement Band: 1930 - 2011
Observation Band: 2012 - 2014

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	1,077	55	0.05108	0.94892	0.35807
74.5	1,014	57	0.05623	0.94377	0.33978
75.5	847	36	0.04213	0.95787	0.32067
76.5	1,181	52	0.04432	0.95568	0.30716
77.5	1,017	47	0.04590	0.95410	0.29355
78.5	530	27	0.05094	0.94906	0.28007
79.5	144	4	0.03007	0.96993	0.26581
80.5	77	4	0.04775	0.95225	0.25781
81.5	85	2	0.02342	0.97658	0.24550
82.5	65	2	0.02554	0.97446	0.23975
83.5	39	1	0.03382	0.96618	0.23363
84.5	0	0	0.00000	1.00000	0.22573

Schedule B1

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES2 Poles - Physically Removed

T-Cut: None
Placement Band: 1930-2011
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2012-2014	22.6	69.7	L0	5.09	57.2	SC	2.14	58.0	SC	2.39

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES2 Poles - Physically Removed

T-Cut: None
Placement Band: 1930-2011
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2012-2014	22.6	69.7	L0	5.09	57.2	SC	2.14	58.0	SC	2.39
2014-2014	22.5	69.8	L0	4.76	56.6	SC	3.28	57.3	SC	3.59

Schedule B3

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES2 Poles - Physically Removed

T-Cut: None

Placement Band: 1930-2011

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2012-2013	23.6	69.7	L0	4.96	57.4	SC	1.94	58.4	SC	2.16
2012-2014	22.6	69.7	L0	5.09	57.2	SC	2.14	58.0	SC	2.39

Schedule C

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES2 Poles - Physically Removed

T-Cut: None

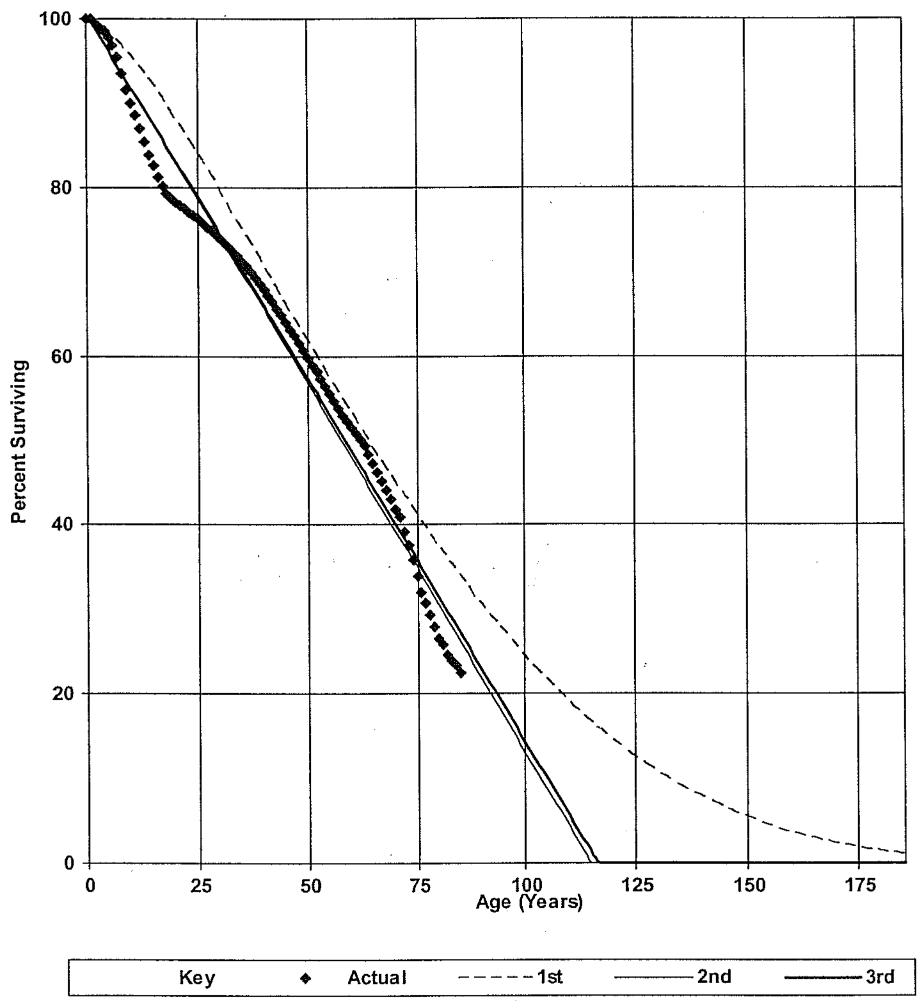
Placement Band: 1930-2011 Observation Band: 2012-2014

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 69.7-L0 2nd: 57.2-SC 3rd: 58.0-SC



Schedule D

HYDRO ONE NETWORKS INC.

Distribution Lines

Account: DXPOLES2 Poles - Physically Removed

T-Cut: None

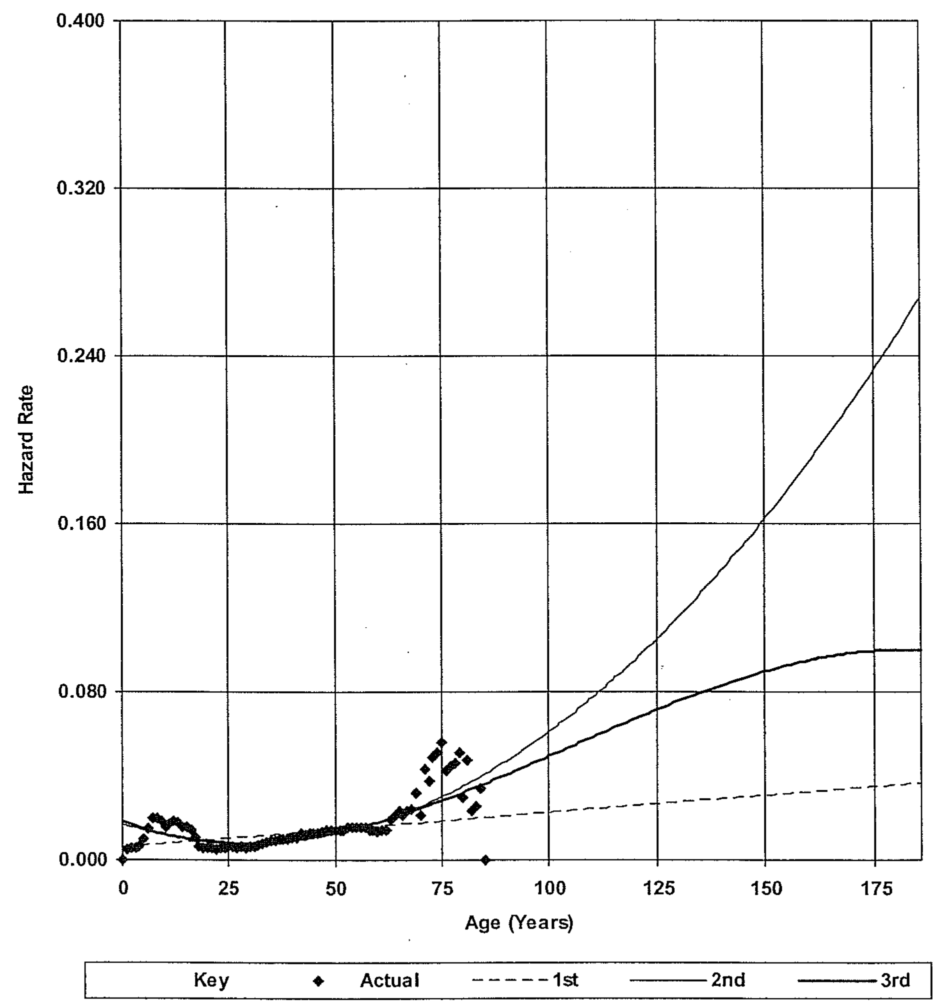
Placement Band: 1930-2011 Observation Band: 2012-2014

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 69.7-L0 2nd: 57.2-SC 3rd: 58.0-SC



Schedule E

HYDRO ONE NETWORKS INC.

Distribution Lines

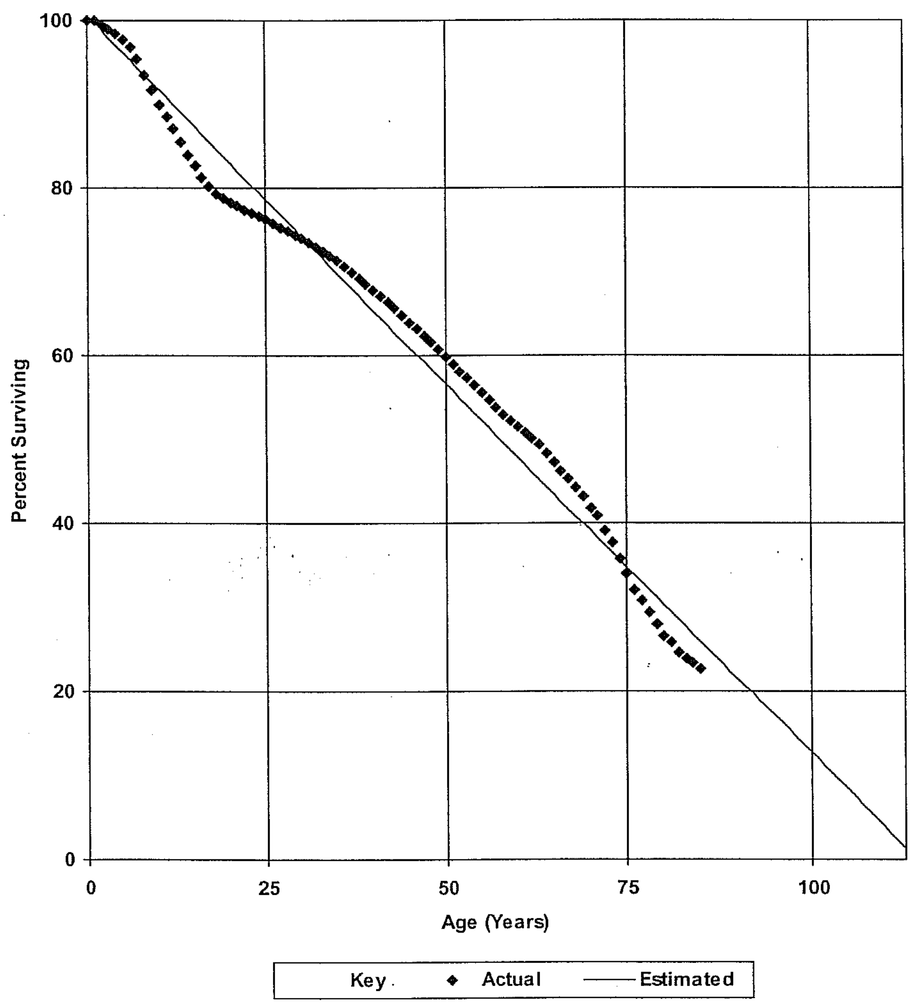
Account: DXPOLES2 Poles - Physically Removed

T-Cut: None

Placement Band: 1930-2011

Observation Band: 2012-2014

Estimated Projection Life Curve 57.0-SC



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

Placement Band: 1905 - 2012
Observation Band: 1988 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	2,679,470	0	0.00000	1.00000	1.00000
0.5	2,885,080	0	0.00000	1.00000	1.00000
1.5	2,562,270	0	0.00000	1.00000	1.00000
2.5	2,516,530	0	0.00000	1.00000	1.00000
3.5	2,470,320	0	0.00000	1.00000	1.00000
4.5	2,419,620	0	0.00000	1.00000	1.00000
5.5	2,553,970	0	0.00000	1.00000	1.00000
6.5	2,659,950	0	0.00000	1.00000	1.00000
7.5	3,347,050	0	0.00000	1.00000	1.00000
8.5	3,362,620	0	0.00000	1.00000	1.00000
9.5	3,592,610	0	0.00000	1.00000	1.00000
10.5	3,925,560	0	0.00000	1.00000	1.00000
11.5	4,189,710	0	0.00000	1.00000	1.00000
12.5	4,596,570	0	0.00000	1.00000	1.00000
13.5	4,621,730	0	0.00000	1.00000	1.00000
14.5	4,646,630	0	0.00000	1.00000	1.00000
15.5	5,098,280	0	0.00000	1.00000	1.00000
16.5	5,487,550	0	0.00000	1.00000	1.00000
17.5	6,920,600	0	0.00000	1.00000	1.00000
18.5	7,121,120	0	0.00000	1.00000	1.00000
19.5	7,098,530	0	0.00000	1.00000	1.00000
20.5	7,199,750	0	0.00000	1.00000	1.00000
21.5	7,359,300	0	0.00000	1.00000	1.00000
22.5	7,456,530	0	0.00000	1.00000	1.00000
23.5	7,335,920	0	0.00000	1.00000	1.00000
24.5	7,802,500	0	0.00000	1.00000	1.00000
25.5	7,756,410	0	0.00000	1.00000	1.00000
26.5	7,783,860	0	0.00000	1.00000	1.00000
27.5	7,768,760	0	0.00000	1.00000	1.00000
28.5	8,033,640	0	0.00000	1.00000	1.00000
29.5	8,663,200	0	0.00000	1.00000	1.00000
30.5	9,101,780	0	0.00000	1.00000	1.00000
31.5	9,155,020	0	0.00000	1.00000	1.00000
32.5	9,396,330	0	0.00000	1.00000	1.00000
33.5	9,065,160	0	0.00000	1.00000	1.00000
34.5	9,327,700	0	0.00000	1.00000	1.00000
35.5	9,491,820	0	0.00000	1.00000	1.00000

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

Placement Band: 1905 - 2012
Observation Band: 1988 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	9,631,725	0	0.00000	1.00000	1.00000
37.5	11,546,655	0	0.00000	1.00000	1.00000
38.5	11,142,945	0	0.00000	1.00000	1.00000
39.5	11,551,455	0	0.00000	1.00000	1.00000
40.5	11,430,585	0	0.00000	1.00000	1.00000
41.5	11,175,245	0	0.00000	1.00000	1.00000
42.5	10,731,855	16,587	0.00155	0.99845	1.00000
43.5	9,265,218	11,058	0.00119	0.99881	0.99845
44.5	9,177,341	65,936	0.00718	0.99282	0.99726
45.5	8,793,736	0	0.00000	1.00000	0.99010
46.5	9,014,496	65,936	0.00731	0.99269	0.99010
47.5	9,031,700	0	0.00000	1.00000	0.98286
48.5	8,759,180	0	0.00000	1.00000	0.98286
49.5	8,589,830	0	0.00000	1.00000	0.98286
50.5	8,453,047	0	0.00000	1.00000	0.98286
51.5	8,449,087	0	0.00000	1.00000	0.98286
52.5	8,318,737	2,907	0.00035	0.99965	0.98286
53.5	8,667,722	23,960	0.00276	0.99724	0.98251
54.5	8,471,402	11,980	0.00141	0.99859	0.97980
55.5	8,333,812	0	0.00000	1.00000	0.97841
56.5	8,257,172	0	0.00000	1.00000	0.97841
57.5	8,324,960	0	0.00000	1.00000	0.97841
58.5	8,330,860	3,340	0.00040	0.99960	0.97841
59.5	9,008,301	0	0.00000	1.00000	0.97802
60.5	8,736,891	155,806	0.01783	0.98217	0.97802
61.5	8,246,365	38,473	0.00467	0.99533	0.96058
62.5	7,777,952	8,393	0.00108	0.99892	0.95610
63.5	5,877,008	18,626	0.00317	0.99683	0.95506
64.5	5,791,832	82,727	0.01428	0.98572	0.95204
65.5	5,359,426	47,809	0.00892	0.99108	0.93844
66.5	5,117,570	20,190	0.00395	0.99605	0.93007
67.5	5,863,601	23,175	0.00395	0.99605	0.92640
68.5	5,746,267	5,173	0.00090	0.99910	0.92274
69.5	5,741,094	637,963	0.11112	0.88888	0.92191
70.5	5,063,490	0	0.00000	1.00000	0.81946
71.5	5,040,590	4,625	0.00092	0.99908	0.81946
72.5	4,993,615	196,440	0.03934	0.96066	0.81871

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

Placement Band: 1905 - 2012
Observation Band: 1988 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	4,597,875	782,583	0.17021	0.82979	0.78650
74.5	3,576,242	0	0.00000	1.00000	0.65264
75.5	3,571,552	13,272	0.00372	0.99628	0.65264
76.5	3,297,380	0	0.00000	1.00000	0.65021
77.5	4,006,007	0	0.00000	1.00000	0.65021
78.5	3,903,297	0	0.00000	1.00000	0.65021
79.5	3,557,707	132,544	0.03726	0.96274	0.65021
80.5	3,322,753	0	0.00000	1.00000	0.62599
81.5	2,822,303	182,160	0.06454	0.93546	0.62599
82.5	2,228,811	0	0.00000	1.00000	0.58558
83.5	2,137,561	463,771	0.21696	0.78304	0.58558
84.5	1,491,020	0	0.00000	1.00000	0.45853
85.5	1,172,160	56,850	0.04850	0.95150	0.45853
86.5	1,100,380	0	0.00000	1.00000	0.43630
87.5	1,037,670	0	0.00000	1.00000	0.43630
88.5	1,022,320	0	0.00000	1.00000	0.43630
89.5	740,160	0	0.00000	1.00000	0.43630
90.5	725,390	0	0.00000	1.00000	0.43630
91.5	634,800	0	0.00000	1.00000	0.43630
92.5	634,800	0	0.00000	1.00000	0.43630
93.5	543,380	0	0.00000	1.00000	0.43630
94.5	543,380	0	0.00000	1.00000	0.43630
95.5	543,380	0	0.00000	1.00000	0.43630
96.5	543,380	0	0.00000	1.00000	0.43630
97.5	543,380	0	0.00000	1.00000	0.43630
98.5	261,120	0	0.00000	1.00000	0.43630
99.5	169,300	0	0.00000	1.00000	0.43630
100.5	169,300	0	0.00000	1.00000	0.43630
101.5	169,300	0	0.00000	1.00000	0.43630
102.5	169,300	0	0.00000	1.00000	0.43630
103.5	3,500	0	0.00000	1.00000	0.43630
104.5	3,500	0	0.00000	1.00000	0.43630
105.5	3,500	0	0.00000	1.00000	0.43630
106.5	3,500	0	0.00000	1.00000	0.43630
107.5	0	0	0.00000	1.00000	0.43630

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

T-Cut: None
Placement Band: 1905-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-1992	3.1	74.9	L3 *	9.90	71.2	R3 *	8.86	74.0	R4 *	8.88
1989-1993	3.3	76.9	L3 *	11.45	72.7	R3 *	9.43	74.3	S3 *	8.99
1990-1994	10.8	65.1	L3 *	16.80	57.8	R1.5 *	18.80	69.6	R4 *	7.17
1991-1995	22.4	79.0	L3 *	14.88	66.6	R2 *	18.57	73.1	R4 *	11.13
1992-1996	17.9	76.2	L3 *	17.05	64.4	R2 *	21.06	71.5	R4 *	13.56
1993-1997	17.9	76.7	L3 *	16.62	64.4	R2 *	21.02	71.8	R4 *	13.33
1994-1998	19.7	73.7	L3 *	13.50	64.3	R2 *	17.12	72.2	R4 *	10.50
1995-1999	51.7	102.3	L2 *	5.01	94.2	S2 *	4.65	122.5	L0.5 *	4.62
1996-2000	59.9	115.4	L2 *	5.39	102.8	S2 *	5.51	120.9	L1.5 *	5.15
1997-2001	78.1	138.9	S1 *	5.24	150.1	R1 *	5.15	171.1	R1.5 *	4.26
1998-2002	10.9	71.6	L3 *	15.27	70.3	R3 *	11.10	68.7	R3 *	12.57
1999-2003	11.8	74.6	L3 *	17.02	71.8	R3 *	13.55	70.4	R3 *	14.74
2000-2004	20.5	75.4	L3 *	16.63	72.9	R3 *	13.46	69.8	R2.5 *	16.21
2001-2005	25.3	75.9	L3 *	16.35	74.0	R3 *	13.24	68.3	R2 *	18.67
2002-2006	38.9	76.4	L3 *	17.20	75.2	S3 *	14.86	67.8	R1.5 *	22.78
2003-2007	98.8	192.1	R5 *	0.35	184.8	R4 *	0.42	194.9	S6 *	0.56
2004-2008	99.1	192.4	R5 *	0.43	186.1	R4 *	0.50	195.4	SQ *	0.71
2005-2009	100.0				No Retirements					
2006-2010	100.0				No Retirements					
2007-2011	100.0				No Retirements					
2008-2012	100.0				No Retirements					
2009-2013	100.0				No Retirements					

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

T-Cut: None
Placement Band: 1905-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-2013	43.6	94.4	L3 *	6.96	88.5	S3 *	6.76	91.6	L3 *	7.97
1990-2013	43.4	93.3	L3 *	7.28	88.3	S3 *	6.98	93.6	L2 *	8.65
1992-2013	50.1	100.8	L3 *	6.51	92.4	S3 *	6.73	94.9	L3 *	7.73
1994-2013	48.4	98.5	L3 *	6.68	91.4	S3 *	6.74	95.5	L3 *	8.26
1996-2013	63.0	110.6	S1.5 *	5.60	101.7	S3 *	6.21	130.6	SC *	7.69
1998-2013	65.0	110.7	S1.5 *	6.12	102.7	S2 *	6.63	133.7	SC *	8.67
2000-2013	66.4	111.5	S1.5 *	6.76	102.8	S3 *	7.23	131.3	SC *	10.14
2002-2013	64.5	106.9	L3 *	7.66	100.2	S3 *	7.96	124.9	SC *	12.51
2004-2013	99.4	196.0	SQ *	0.17	194.1	S6 *	0.20	197.6	S6 *	0.28
2006-2013	100.0				No Retirements					
2008-2013	100.0				No Retirements					
2010-2013	100.0				No Retirements					
2012-2013	100.0				No Retirements					

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

T-Cut: None

Placement Band: 1905-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-1989	0.0	129.3	S0.5 *	19.61	107.0	S2	19.96	89.6	R4 *	20.11
1988-1991	2.4	69.5	L3 *	9.73	66.5	R3 *	9.62	71.3	R4 *	9.57
1988-1993	3.4	80.2	L3 *	11.89	75.4	R3 *	10.05	76.8	S3 *	9.97
1988-1995	12.6	71.8	L3 *	13.18	64.5	R2.5 *	13.67	72.8	R4 *	6.05
1988-1997	10.3	75.9	L3 *	12.91	67.6	R2.5 *	12.54	74.7	R4 *	6.11
1988-1999	23.5	78.7	L3 *	10.99	71.6	R3 *	10.51	77.2	S4 *	5.01
1988-2001	31.0	84.0	L3 *	9.23	76.2	R3 *	8.39	80.3	S4 *	4.63
1988-2003	18.7	75.7	L3 *	12.46	70.2	R3 *	10.81	76.2	S4 *	5.28
1988-2005	23.1	79.1	L3 *	11.13	73.6	R3 *	9.34	77.2	R4 *	6.10
1988-2007	27.7	82.8	L3 *	9.74	77.1	R3 *	7.96	78.5	S3 *	6.78
1988-2009	33.3	86.6	L3 *	8.47	80.8	R3 *	7.11	80.4	R3 *	7.41
1988-2011	37.7	90.4	L3 *	7.73	84.6	S3 *	6.69	83.5	R2.5 *	7.80
1988-2013	43.6	94.4	L3 *	6.96	88.5	S3 *	6.76	91.6	L3 *	7.97

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

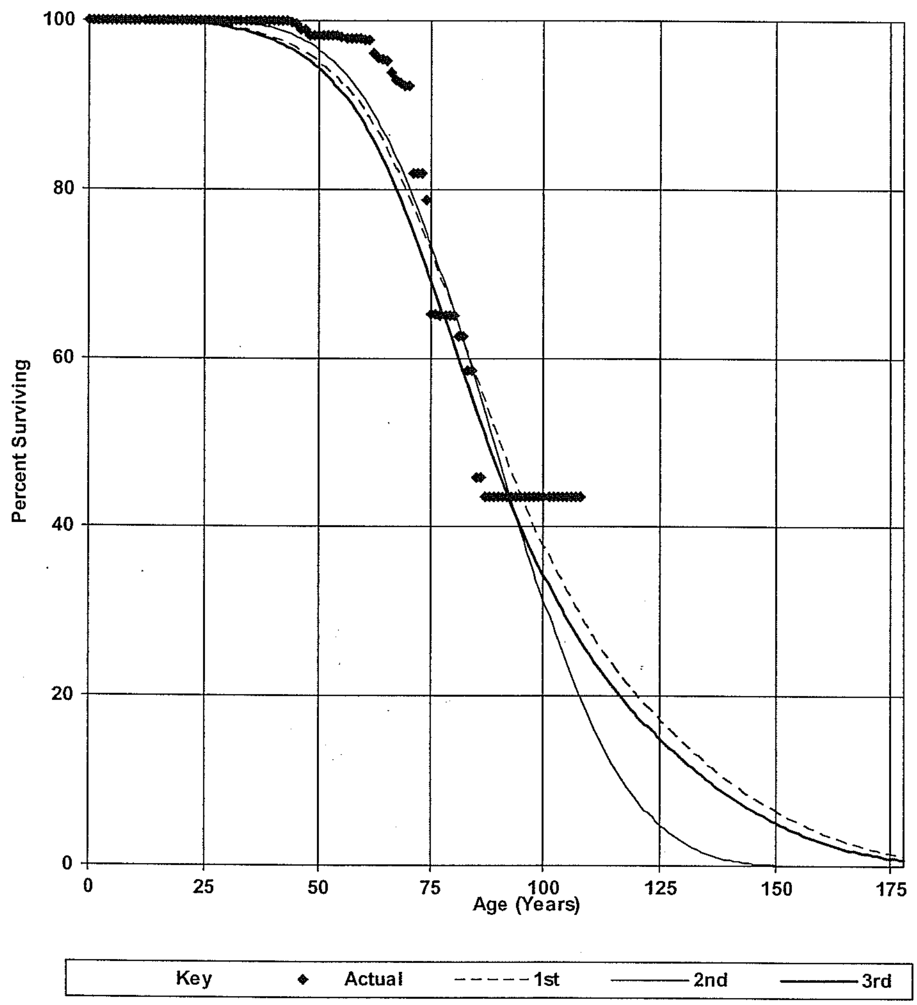
T-Cut: None

Placement Band: 1905-2012 Observation Band: 1988-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 94.4-L3 2nd: 88.5-S3 3rd: 91.6-L3



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

T-Cut: None

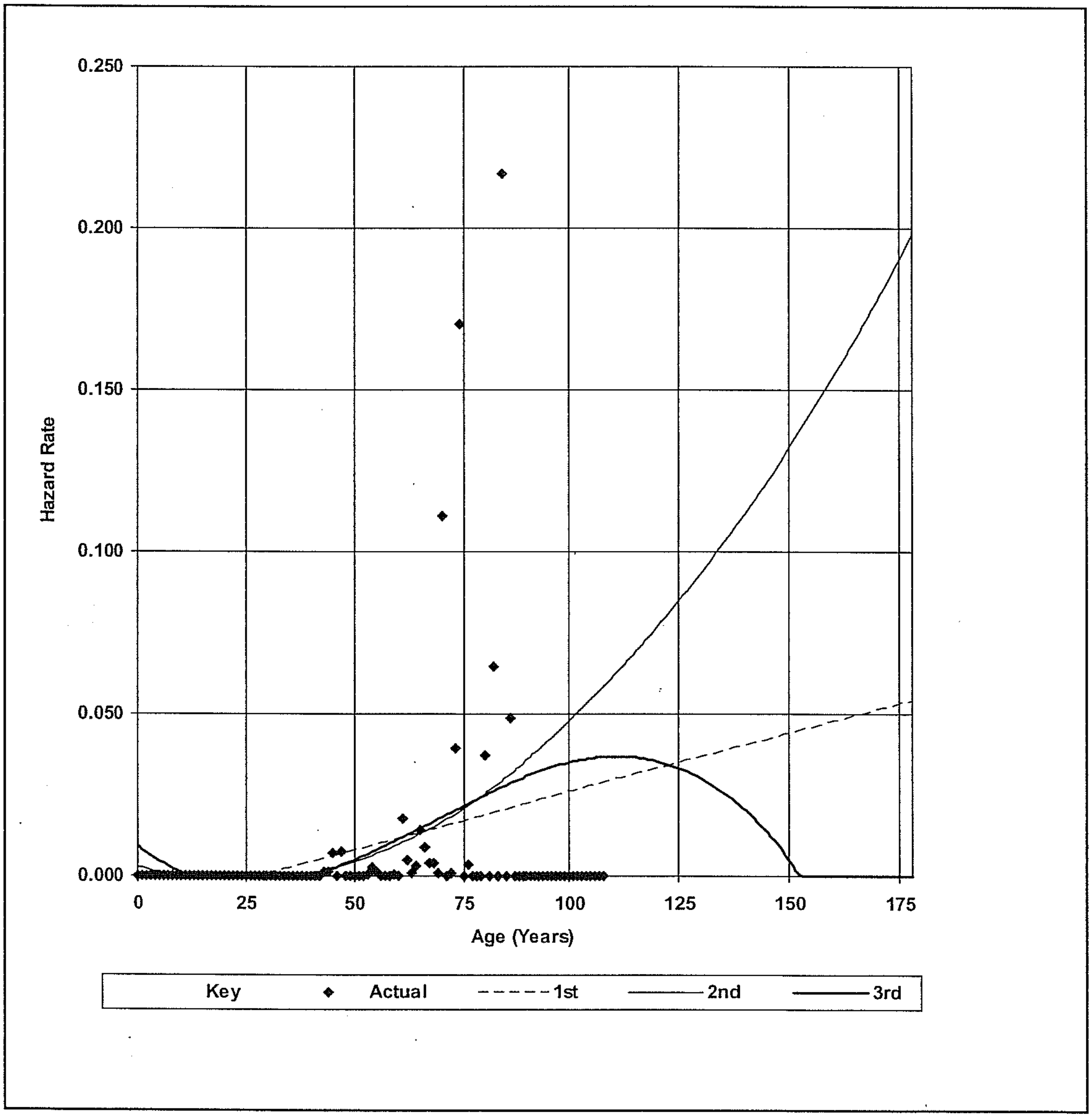
Placement Band: 1905-2012 Observation Band: 1988-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 94.4-L3 2nd: 88.5-S3 3rd: 91.6-L3



HYDRO ONE NETWORKS INC.

Transmission Lines

Account: OHLINES Overhead Lines (in Metres)

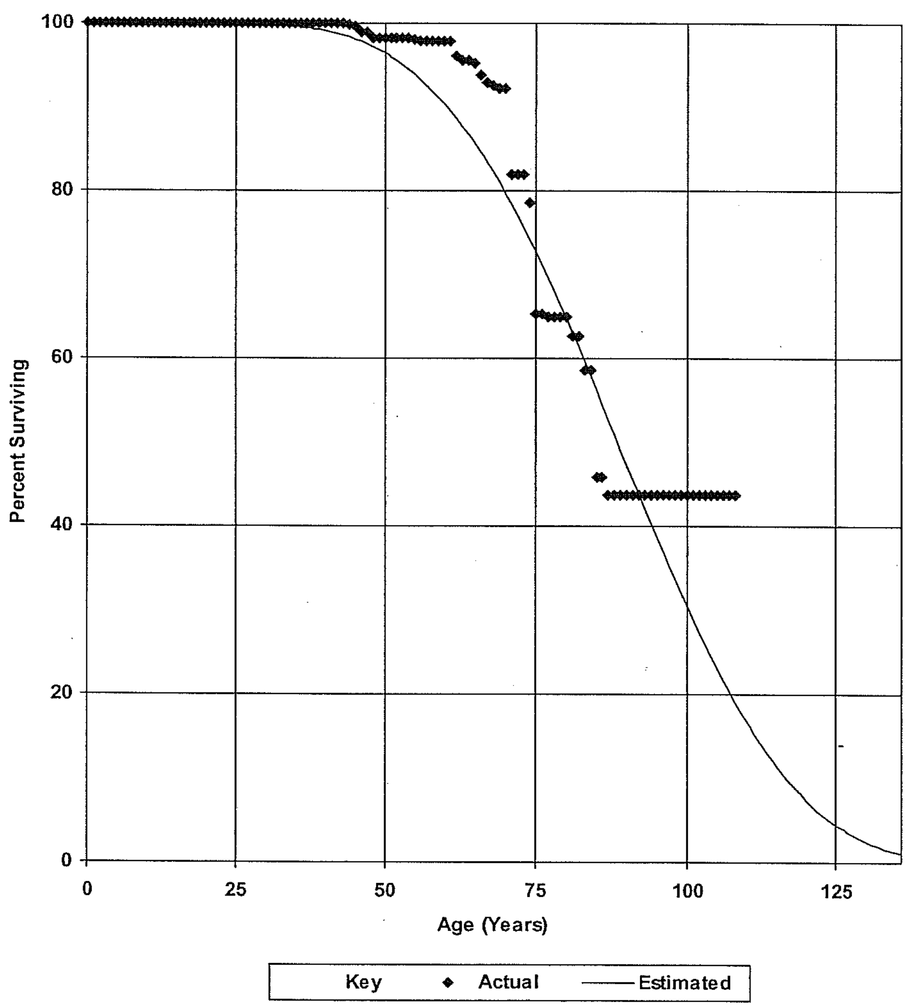
T-Cut: None

Placement Band: 1905-2012

Observation Band: 1988-2013

88.0-S3

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

Placement Band: 1910 - 2013
Observation Band: 1929 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	44,110	0	0.00000	1.00000	1.00000
0.5	45,342	52	0.00115	0.99885	1.00000
1.5	45,230	5	0.00011	0.99989	0.99885
2.5	45,157	20	0.00044	0.99956	0.99874
3.5	45,148	1	0.00002	0.99998	0.99830
4.5	44,901	1	0.00002	0.99998	0.99828
5.5	44,892	10	0.00022	0.99978	0.99826
6.5	45,091	10	0.00022	0.99978	0.99803
7.5	45,037	3	0.00007	0.99993	0.99781
8.5	45,020	0	0.00000	1.00000	0.99775
9.5	44,928	4	0.00009	0.99991	0.99775
10.5	44,568	3	0.00007	0.99993	0.99766
11.5	44,544	3	0.00007	0.99993	0.99759
12.5	44,538	3	0.00007	0.99993	0.99752
13.5	44,761	5	0.00011	0.99989	0.99746
14.5	45,577	5	0.00011	0.99989	0.99734
15.5	45,571	3	0.00007	0.99993	0.99723
16.5	45,565	6	0.00013	0.99987	0.99717
17.5	45,558	11	0.00024	0.99976	0.99704
18.5	47,316	2	0.00004	0.99996	0.99680
19.5	46,568	12	0.00026	0.99974	0.99675
20.5	46,556	5	0.00011	0.99989	0.99650
21.5	46,509	19	0.00041	0.99959	0.99639
22.5	45,038	1	0.00002	0.99998	0.99598
23.5	44,150	1	0.00002	0.99998	0.99596
24.5	43,770	0	0.00000	1.00000	0.99594
25.5	42,893	4	0.00009	0.99991	0.99594
26.5	42,327	0	0.00000	1.00000	0.99585
27.5	42,285	2	0.00005	0.99995	0.99585
28.5	42,283	10	0.00024	0.99976	0.99580
29.5	42,273	1	0.00002	0.99998	0.99556
30.5	42,063	26	0.00062	0.99938	0.99554
31.5	41,699	9	0.00022	0.99978	0.99492
32.5	41,386	22	0.00053	0.99947	0.99471
33.5	38,835	2	0.00005	0.99995	0.99418
34.5	38,771	3	0.00008	0.99992	0.99413
35.5	38,206	17	0.00044	0.99956	0.99405

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

Placement Band: 1910 - 2013
Observation Band: 1929 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	37,584	6	0.00016	0.99984	0.99361
37.5	36,991	10	0.00027	0.99973	0.99345
38.5	35,818	12	0.00034	0.99966	0.99318
39.5	35,552	8	0.00023	0.99977	0.99285
40.5	35,454	15	0.00042	0.99958	0.99263
41.5	34,721	1	0.00003	0.99997	0.99221
42.5	33,943	2	0.00006	0.99994	0.99218
43.5	30,472	0	0.00000	1.00000	0.99212
44.5	29,868	14	0.00047	0.99953	0.99212
45.5	29,142	5	0.00017	0.99983	0.99166
46.5	29,085	29	0.00100	0.99900	0.99149
47.5	28,660	9	0.00031	0.99969	0.99050
48.5	27,797	6	0.00022	0.99978	0.99019
49.5	27,630	78	0.00282	0.99718	0.98997
50.5	26,305	8	0.00030	0.99970	0.98718
51.5	26,257	11	0.00042	0.99958	0.98688
52.5	25,647	0	0.00000	1.00000	0.98646
53.5	25,638	1	0.00004	0.99996	0.98646
54.5	25,297	0	0.00000	1.00000	0.98643
55.5	24,726	4	0.00016	0.99984	0.98643
56.5	24,317	2	0.00008	0.99992	0.98627
57.5	24,199	7	0.00029	0.99971	0.98618
58.5	23,408	5	0.00021	0.99979	0.98590
59.5	22,069	14	0.00063	0.99937	0.98569
60.5	21,737	6	0.00028	0.99972	0.98506
61.5	20,936	8	0.00038	0.99962	0.98479
62.5	20,416	1	0.00005	0.99995	0.98442
63.5	14,865	1	0.00007	0.99993	0.98437
64.5	14,643	1	0.00007	0.99993	0.98430
65.5	13,914	0	0.00000	1.00000	0.98423
66.5	13,195	1	0.00008	0.99992	0.98423
67.5	12,503	2	0.00016	0.99984	0.98416
68.5	12,497	2	0.00016	0.99984	0.98400
69.5	12,495	4	0.00032	0.99968	0.98384
70.5	12,475	0	0.00000	1.00000	0.98353
71.5	12,407	0	0.00000	1.00000	0.98353
72.5	11,679	1	0.00009	0.99991	0.98353

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

Placement Band: 1910 - 2013
Observation Band: 1929 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	10,854	0	0.00000	1.00000	0.98344
74.5	10,852	0	0.00000	1.00000	0.98344
75.5	10,817	3	0.00028	0.99972	0.98344
76.5	10,800	0	0.00000	1.00000	0.98317
77.5	10,791	0	0.00000	1.00000	0.98317
78.5	10,470	0	0.00000	1.00000	0.98317
79.5	9,819	2	0.00020	0.99980	0.98317
80.5	9,520	0	0.00000	1.00000	0.98297
81.5	7,629	0	0.00000	1.00000	0.98297
82.5	5,833	0	0.00000	1.00000	0.98297
83.5	5,712	1	0.00018	0.99982	0.98297
84.5	4,985	0	0.00000	1.00000	0.98280
85.5	3,754	0	0.00000	1.00000	0.98280
86.5	3,745	5	0.00134	0.99866	0.98280
87.5	3,734	0	0.00000	1.00000	0.98149
88.5	3,610	3	0.00083	0.99917	0.98149
89.5	3,364	0	0.00000	1.00000	0.98067
90.5	3,308	0	0.00000	1.00000	0.98067
91.5	2,928	5	0.00171	0.99829	0.98067
92.5	2,920	0	0.00000	1.00000	0.97900
93.5	2,917	0	0.00000	1.00000	0.97900
94.5	2,917	0	0.00000	1.00000	0.97900
95.5	2,917	0	0.00000	1.00000	0.97900
96.5	2,917	0	0.00000	1.00000	0.97900
97.5	2,916	1	0.00034	0.99966	0.97900
98.5	2,615	1	0.00038	0.99962	0.97866
99.5	1,765	0	0.00000	1.00000	0.97829
100.5	1,765	6	0.00340	0.99660	0.97829
101.5	1,759	6	0.00341	0.99659	0.97496
102.5	1,753	0	0.00000	1.00000	0.97164
103.5	0	0	0.00000	1.00000	0.97164

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

T-Cut: None
Placement Band: 1910-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1929-1933	99.5	198.6	SQ*	0.32	198.3	SQ*	0.23	61.6	R4*	0.17
1930-1934	99.9	198.9	SQ*	0.02	198.8	SQ*	0.03	82.1	S3*	0.03
1931-1935	100.0				No Retirements					
1932-1936	100.0				No Retirements					
1933-1937	100.0				No Retirements					
1934-1938	100.0				No Retirements					
1935-1939	100.0				No Retirements					
1936-1940	100.0	198.9	SQ*	0.01	198.8	SQ*	0.02	124.8	S3*	0.02
1937-1941	100.0	198.9	SQ*	0.01	198.9	SQ*	0.02	130.2	S3*	0.01
1938-1942	100.0	198.9	SQ*	0.02	198.9	SQ*	0.02	139.0	S3*	0.01
1939-1943	100.0	198.9	SQ*	0.02	198.9	SQ*	0.02	139.2	S3*	0.02
1940-1944	100.0	198.9	SQ*	0.02	198.9	SQ*	0.02	136.8	S3*	0.01
1941-1945	100.0				No Retirements					
1942-1946	100.0				No Retirements					
1943-1947	100.0	198.9	SQ*	0.02	198.9	SQ*	0.02	151.0	S3*	0.02
1944-1948	100.0	198.9	SQ*	0.03	198.9	SQ*	0.02	147.3	S3*	0.02
1945-1949	100.0	198.9	SQ*	0.03	198.9	SQ*	0.02	145.8	S3*	0.02
1946-1950	99.8	198.3	SQ*	0.13	155.9	R3*	0.17	198.0	SQ*	0.20
1947-1951	99.9	198.4	SQ*	0.13	176.7	R3*	0.11	198.5	SQ*	0.10
1948-1952	99.9	198.5	SQ*	0.14	175.7	R3*	0.11	198.5	SQ*	0.10
1949-1953	99.6	198.3	SQ*	0.06	185.9	R4	0.05	198.3	SQ*	0.05
1950-1954	99.2	198.0	SQ*	0.13	180.0	R4	0.16	198.0	SQ*	0.16
1951-1955	99.0	198.2	SQ*	0.41	194.0	S6	0.43	198.3	SQ*	0.43
1952-1956	98.8	197.3	SQ*	0.34	197.7	SQ*	0.34	197.9	SQ*	0.33
1953-1957	98.5	196.1	SQ	0.45	197.7	SQ*	0.45	197.8	SQ*	0.43
1954-1958	99.1	197.9	SQ*	0.25	192.6	R5	0.27	198.0	SQ*	0.21
1955-1959	99.5	197.1	SQ	0.15	198.5	SQ*	0.14	198.4	SQ*	0.13
1956-1960	99.3	197.3	SQ	0.27	198.5	SQ*	0.26	198.4	SQ*	0.25
1957-1961	99.7	198.2	SQ*	0.13	188.9	R5*	0.11	174.7	R4*	0.11
1958-1962	99.7	198.2	SQ*	0.09	185.6	R4*	0.06	177.6	R4*	0.06
1959-1963	99.6	198.3	SQ*	0.07	185.6	R4*	0.07	198.3	SQ*	0.07
1960-1964	99.4	197.9	SQ*	0.09	169.2	R3*	0.06	197.5	S6*	0.10
1961-1965	99.2	197.7	SQ*	0.09	169.1	R3*	0.06	197.4	SQ*	0.09
1962-1966	99.4	198.3	SQ*	0.11	182.0	R4*	0.11	198.1	SQ*	0.06
1963-1967	99.6	198.1	SQ*	0.07	183.0	R4*	0.06	198.0	SQ*	0.09
1964-1968	99.5	198.0	SQ*	0.04	185.5	R4*	0.02	198.0	SQ*	0.03
1965-1969	99.7	198.3	SQ*	0.03	196.5	S6*	0.03	172.9	R4*	0.02
1966-1970	98.8	197.2	SQ*	0.26	197.3	SQ*	0.27	160.1	R4*	0.30

HYDRO ONE NETWORKS INC.
Transmission Lines
Account: STSTRCT Steel Structures

T-Cut: None
Placement Band: 1910-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1967-1971	98.9	197.2	SQ*	0.17	197.2	SQ*	0.17	160.5	R4*	0.19
1968-1972	96.5	187.3	R4	0.78	189.2	R5	0.79	195.1	SQ*	0.72
1969-1973	96.6	187.8	R4	0.78	192.9	S6*	0.78	195.2	SQ*	0.72
1970-1974	94.7	188.2	R4	1.81	194.4	SQ*	1.81	195.4	SQ*	1.75
1971-1975	98.3	188.7	R4*	0.30	194.1	SQ*	0.30	196.4	SQ*	0.25
1972-1976	98.6	189.5	R5*	0.21	195.5	SQ*	0.22	196.5	SQ*	0.20
1973-1977	99.7	198.5	SQ*	0.05	198.5	SQ*	0.05	175.1	R4*	0.04
1974-1978	99.7	198.5	SQ*	0.04	198.5	SQ*	0.04	179.2	R4*	0.03
1975-1979	99.4	198.0	SQ*	0.12	195.9	S6*	0.14	198.1	SQ*	0.14
1976-1980	99.0	197.6	S6*	0.26	193.6	S6*	0.28	197.3	SQ*	0.28
1977-1981	99.2	197.8	SQ*	0.16	192.8	R5*	0.19	197.9	SQ*	0.19
1978-1982	99.3	197.9	SQ*	0.09	194.2	S6*	0.11	197.9	SQ*	0.11
1979-1983	99.2	197.7	SQ*	0.08	191.3	R5*	0.09	188.6	R5*	0.09
1980-1984	99.5	198.2	SQ*	0.06	196.0	S6	0.06	178.6	R4*	0.05
1981-1985	99.8	198.5	SQ	0.03	197.4	SQ	0.03	186.8	R5*	0.02
1982-1986	99.7	198.2	SQ	0.04	196.7	S6	0.04	190.5	R5	0.04
1983-1987	99.7	198.3	SQ	0.04	196.8	S6	0.03	192.5	R5	0.04
1984-1988	99.7	198.4	SQ	0.07	198.8	SQ*	0.06	198.8	SQ*	0.06
1985-1989	99.9	198.4	SQ	0.03	198.8	SQ*	0.04	198.8	SQ*	0.04
1986-1990	99.7	198.3	SQ*	0.06	198.5	SQ*	0.05	196.1	S6*	0.04
1987-1991	98.7	197.3	SQ*	0.34	192.2	R5	0.31	196.8	SQ*	0.20
1988-1992	98.8	197.2	SQ*	0.19	192.9	S6	0.17	196.9	SQ*	0.12
1989-1993	99.1	197.3	SQ*	0.10	192.6	R5	0.09	197.1	SQ*	0.11
1990-1994	99.1	197.2	SQ*	0.13	192.2	R5*	0.16	197.0	SQ*	0.19
1991-1995	99.1	197.5	S6*	0.10	192.3	R5*	0.08	197.3	SQ*	0.07
1992-1996	99.8	198.7	SQ*	0.03	198.1	SQ	0.03	198.7	SQ*	0.03
1993-1997	99.8	198.7	SQ*	0.04	197.5	SQ	0.03	198.6	SQ*	0.03
1994-1998	99.5	198.6	SQ*	0.21	197.4	SQ	0.20	198.5	SQ*	0.16
1995-1999	99.4	197.6	S6	0.17	198.3	SQ*	0.17	198.3	SQ*	0.12
1996-2000	65.3	188.7	R4	10.93	194.4	SQ*	10.95	194.5	S6*	10.93
1997-2001	73.4	189.1	R5	8.42	194.4	SQ*	8.46	194.5	SQ*	8.43
1998-2002	97.2	188.6	R4	0.75	193.8	S6*	0.70	193.9	S6*	0.67
1999-2003	97.0	189.0	R5	0.76	193.8	S6*	0.64	193.8	S6*	0.62
2000-2004	96.8	187.8	R4	1.13	192.4	SQ*	0.73	192.2	SQ*	0.75
2001-2005	98.0	195.0	SQ*	0.45	195.8	SQ*	0.19	179.1	R4*	0.16
2002-2006	90.9	191.0	R5*	4.62	169.9	R3*	3.47	183.7	R4*	1.67
2003-2007	90.2	188.9	R5*	3.98	170.3	R3*	2.88	182.6	R4*	1.47
2004-2008	90.6	187.2	R4*	2.48	171.9	R3	1.61	181.5	R3*	1.12

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

T-Cut: None

Placement Band: 1910-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2005-2009	88.0	187.7	R4 *	5.40	167.6	R2.5	3.99	180.1	R3 *	2.24
2006-2010	91.3	186.0	R4 *	1.35	169.9	R2.5	1.04	179.5	R3 *	2.27
2007-2011	92.7	185.9	R4 *	1.24	188.1	R4 *	0.78	163.0	R4 *	0.40
2008-2012	93.0	185.5	R4	0.90	186.9	R4 *	0.78	168.3	R3 *	0.41
2009-2013	94.1	187.8	R4	0.64	185.6	R4	0.77	173.0	R3	0.46

Schedule B2

HYDRO ONE NETWORKS INC.
Transmission Lines
Account: STSTRCT Steel Structures

T-Cut: None
Placement Band: 1910-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1929-2013	97.2	193.7	S6	0.15	193.7	S6	0.15	195.4	SQ *	0.16
1931-2013	97.2	193.7	S6	0.15	193.7	S6	0.15	195.4	SQ *	0.16
1933-2013	97.2	193.7	S6	0.15	193.7	S6	0.14	195.4	SQ *	0.15
1935-2013	97.1	193.7	S6	0.14	193.6	S6	0.14	195.4	SQ *	0.16
1937-2013	97.1	193.8	S6	0.14	193.6	S6	0.14	195.4	SQ *	0.16
1939-2013	97.1	193.8	S6	0.14	193.5	SQ	0.15	195.4	SQ *	0.16
1941-2013	97.1	193.8	S6	0.14	193.5	SQ	0.15	195.3	SQ *	0.16
1943-2013	97.1	193.8	S6	0.14	193.4	SQ	0.15	195.3	SQ *	0.16
1945-2013	97.1	193.8	S6	0.14	193.4	SQ	0.15	195.3	SQ *	0.16
1947-2013	97.1	193.8	S6	0.15	193.4	SQ	0.15	195.3	SQ *	0.16
1949-2013	97.1	193.8	S6	0.15	193.3	SQ	0.15	195.2	SQ *	0.16
1951-2013	97.1	193.7	S6	0.15	193.5	S6	0.15	195.2	SQ *	0.16
1953-2013	97.0	193.7	S6	0.14	193.4	SQ	0.14	195.2	SQ *	0.15
1955-2013	97.0	193.7	S6	0.14	193.5	SQ	0.14	195.2	SQ *	0.15
1957-2013	97.0	193.7	S6	0.14	193.3	SQ	0.15	195.1	SQ *	0.16
1959-2013	97.0	193.7	S6	0.14	193.2	S6	0.15	195.1	SQ *	0.16
1961-2013	96.9	193.7	S6	0.14	193.1	S6	0.15	195.0	SQ *	0.16
1963-2013	96.9	193.7	S6	0.15	193.4	SQ	0.15	195.0	SQ *	0.16
1965-2013	96.9	193.6	S6	0.15	193.6	S6	0.15	194.9	SQ *	0.16
1967-2013	96.9	193.6	S6	0.15	193.6	S6	0.15	194.9	SQ *	0.16
1969-2013	96.8	193.5	SQ	0.16	193.6	S6	0.16	194.8	S6 *	0.16
1971-2013	96.9	193.4	SQ	0.16	193.8	S6	0.16	194.9	SQ *	0.17
1973-2013	96.8	193.7	S6	0.15	193.3	SQ	0.15	194.9	SQ *	0.16
1975-2013	96.8	193.6	S6	0.16	193.1	S6	0.16	194.8	S6 *	0.17
1977-2013	96.7	193.6	S6	0.17	192.9	S6	0.17	194.7	S6 *	0.17
1979-2013	96.6	193.5	SQ	0.18	192.7	S6	0.18	194.5	SQ *	0.18
1981-2013	96.6	193.2	SQ	0.18	193.3	SQ	0.18	194.5	SQ *	0.18
1983-2013	96.3	193.1	S6	0.25	192.9	S6	0.26	194.2	SQ *	0.25
1985-2013	96.1	193.0	S6	0.29	192.7	S6	0.29	194.0	SQ *	0.27
1987-2013	96.0	192.8	S6	0.26	192.3	R5	0.26	193.6	S6 *	0.25
1989-2013	95.8	192.5	S6	0.25	191.8	R5	0.26	193.3	SQ *	0.25
1991-2013	95.5	192.2	SQ *	0.33	191.3	R5	0.33	192.8	S6 *	0.30
1993-2013	94.8	191.8	R5	0.83	192.1	R5 *	0.87	192.7	S6 *	0.82
1995-2013	94.6	191.3	R5 *	0.70	191.3	R5	0.73	192.0	R5 *	0.67
1997-2013	93.7	190.6	R5 *	1.19	189.9	R5	1.19	190.9	R5 *	1.07
1999-2013	93.3	189.7	R5 *	0.96	188.3	R4	0.92	189.7	R5 *	0.78
2001-2013	93.3	190.5	R5 *	0.96	183.1	R4	0.64	188.7	R5 *	0.52
2003-2013	92.1	189.4	R5 *	1.01	179.9	R4	0.64	187.0	R4 *	0.62

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

T-Cut: None

Placement Band: 1910-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2005-2013	91.1	188.7	R5 *	1.50	175.0	R3	0.83	184.9	R4 *	0.81
2007-2013	93.5	187.9	R4 *	0.88	188.8	R5 *	0.72	166.7	R4 *	0.33
2009-2013	94.1	187.8	R4	0.64	185.6	R4	0.77	173.0	R3	0.46
2011-2013	91.9	186.6	R4	1.08	178.3	R3	0.62	170.0	R3	0.81
2013-2013	100.0				No Retirements					

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

T-Cut: None
Placement Band: 1910-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1929-1930	99.1	197.8	SQ*	0.30	196.6	S6*	0.27	43.7	R4*	0.44
1929-1932	99.5	198.5	SQ*	0.27	198.0	SQ*	0.17	55.6	R4*	0.10
1929-1934	99.8	198.7	SQ*	0.10	198.5	SQ*	0.06	67.3	R4*	0.05
1929-1936	99.9	198.8	SQ*	0.03	198.7	SQ*	0.04	79.6	S3*	0.04
1929-1938	99.9	198.8	SQ*	0.02	198.8	SQ*	0.03	91.9	S3*	0.04
1929-1940	99.9	198.8	SQ*	0.01	198.8	SQ*	0.02	99.9	S3*	0.02
1929-1942	99.9	198.9	SQ*	0.01	198.8	SQ*	0.02	109.5	S3*	0.01
1929-1944	99.9	198.9	SQ*	0.01	198.9	SQ*	0.01	118.1	S3*	0.01
1929-1946	100.0	198.9	SQ*	0.01	198.9	SQ*	0.01	126.9	S3*	0.01
1929-1948	99.9	198.9	SQ*	0.01	198.9	SQ*	0.01	131.8	S3*	0.01
1929-1950	99.9	198.8	SQ*	0.02	187.2	R4*	0.01	198.8	SQ*	0.01
1929-1952	99.9	198.8	SQ*	0.02	189.0	R5*	0.01	198.8	SQ*	0.01
1929-1954	99.8	198.6	SQ*	0.02	185.8	R4	0.01	198.6	SQ*	0.01
1929-1956	99.7	198.5	SQ*	0.03	188.9	R5	0.02	198.5	SQ*	0.02
1929-1958	99.7	198.5	SQ*	0.03	189.9	R5	0.03	198.5	SQ*	0.02
1929-1960	99.7	198.6	SQ*	0.03	192.2	R5	0.03	198.5	SQ*	0.02
1929-1962	99.7	198.5	SQ*	0.03	192.8	R5	0.02	198.5	SQ*	0.02
1929-1964	99.7	198.5	SQ*	0.03	189.5	R5	0.02	198.4	SQ*	0.02
1929-1966	99.7	198.5	SQ*	0.03	191.5	R5	0.02	198.4	SQ*	0.02
1929-1968	99.7	198.4	SQ*	0.02	193.7	S6	0.02	198.4	SQ*	0.02
1929-1970	99.6	198.2	SQ*	0.02	197.0	SQ	0.02	198.2	SQ*	0.02
1929-1972	99.0	195.6	S6	0.14	184.4	R4	0.13	197.1	SQ*	0.12
1929-1974	99.0	196.1	SQ	0.15	188.5	R5	0.14	197.5	SQ*	0.13
1929-1976	99.2	196.5	SQ	0.08	191.9	R5	0.08	197.6	S6*	0.07
1929-1978	99.3	196.9	SQ	0.06	193.9	S6	0.06	197.7	SQ*	0.05
1929-1980	99.3	197.5	S6*	0.05	194.3	S6	0.05	197.7	SQ*	0.05
1929-1982	99.4	197.7	SQ*	0.04	195.4	SQ	0.04	197.8	SQ*	0.04
1929-1984	99.3	197.7	SQ*	0.04	195.4	SQ	0.04	197.8	SQ*	0.04
1929-1986	99.3	197.8	SQ*	0.04	195.7	S6	0.04	197.9	SQ*	0.03
1929-1988	99.4	197.9	SQ*	0.03	196.4	SQ	0.03	197.9	SQ*	0.03
1929-1990	99.4	197.9	SQ*	0.03	197.0	SQ	0.03	197.9	SQ*	0.03
1929-1992	99.3	197.9	SQ*	0.04	196.4	SQ	0.04	197.8	SQ*	0.03
1929-1994	99.4	197.9	SQ*	0.04	196.7	S6	0.04	197.9	SQ*	0.03
1929-1996	99.4	198.0	SQ*	0.03	196.8	SQ	0.04	197.9	SQ*	0.03
1929-1998	99.4	198.0	SQ*	0.03	196.7	S6	0.03	197.9	SQ*	0.03
1929-2000	98.9	195.9	SQ	0.09	195.5	SQ	0.09	197.2	SQ*	0.09
1929-2002	98.9	195.9	SQ	0.09	196.5	S6*	0.09	197.1	SQ*	0.09
1929-2004	98.8	195.6	S6	0.12	196.9	SQ*	0.09	197.0	SQ*	0.10

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

T-Cut: None

Placement Band: 1910-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1929-2006	98.6	196.0	SQ	0.10	194.6	S6	0.11	196.7	SQ *	0.12
1929-2008	98.4	195.3	SQ	0.13	196.1	SQ *	0.11	196.4	SQ *	0.13
1929-2010	98.2	194.8	S6	0.14	196.0	SQ *	0.11	196.2	SQ *	0.12
1929-2012	97.1	193.5	SQ	0.15	193.2	S6	0.16	195.3	SQ *	0.16
1929-2013	97.2	193.7	S6	0.15	193.7	S6	0.15	195.4	SQ *	0.16

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

T-Cut: None

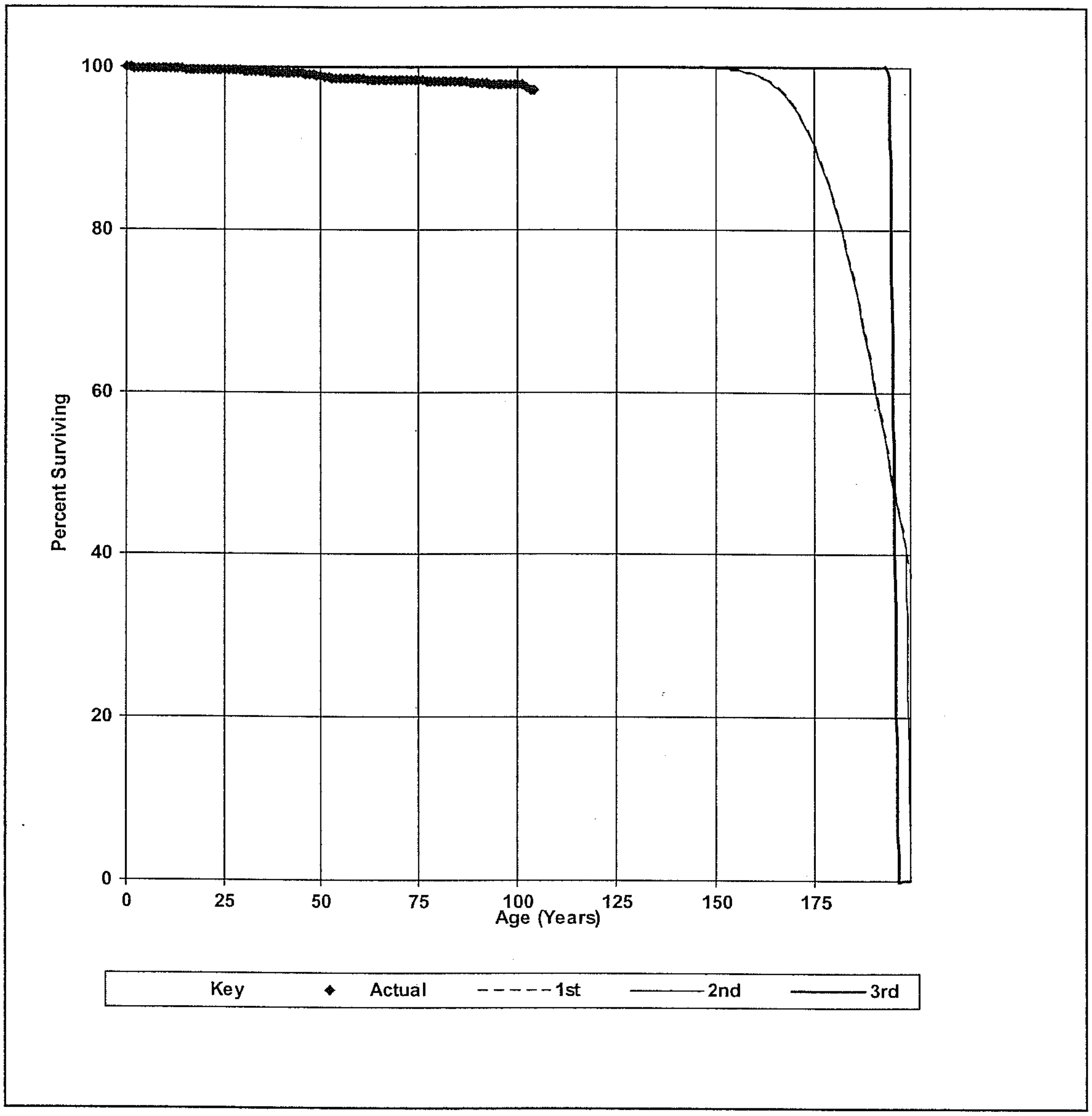
Placement Band: 1910-2013 Observation Band: 1929-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 193.7-S6 2nd: 193.7-S6 3rd: 195.4-SQ



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

T-Cut: None

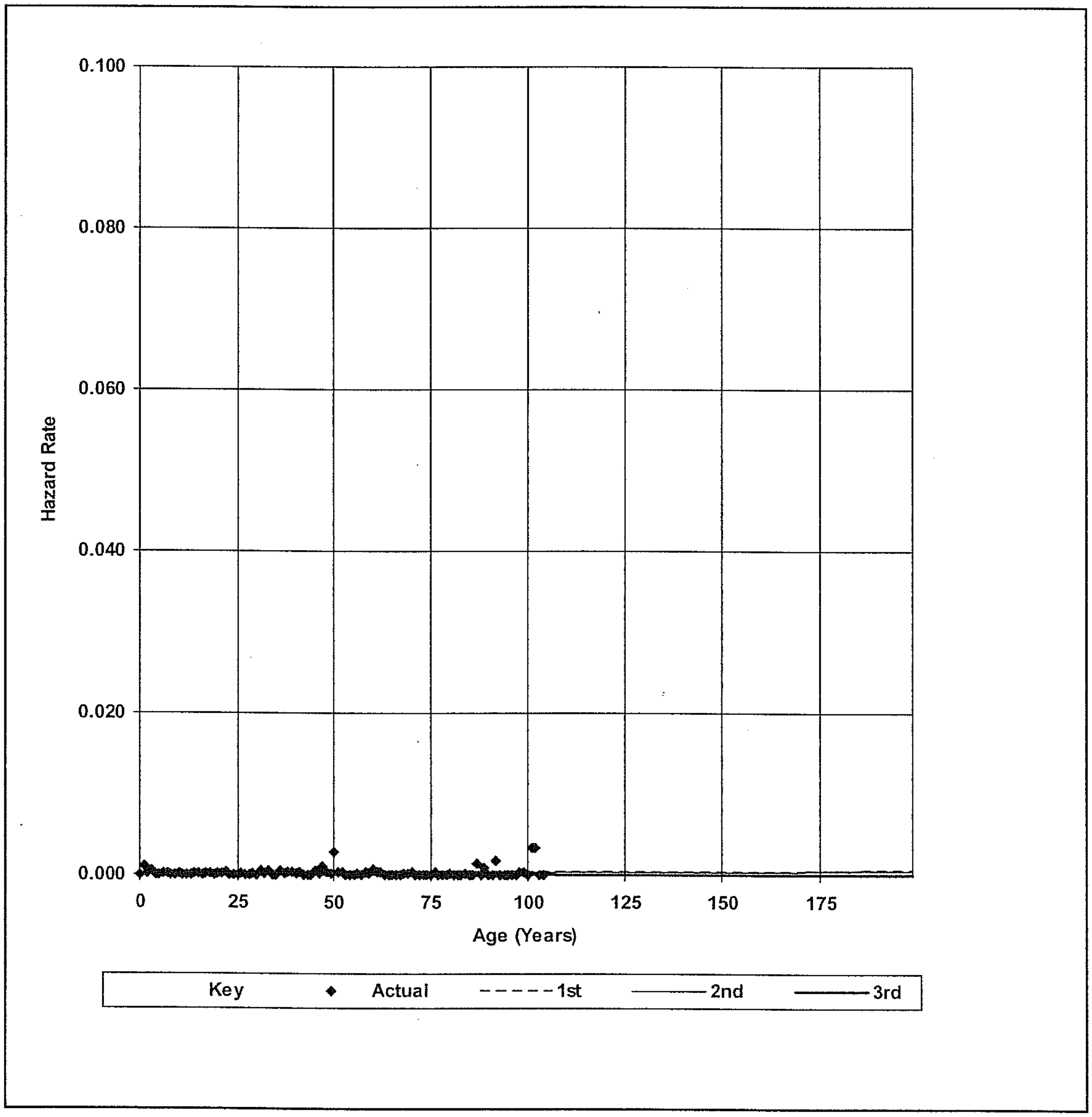
Placement Band: 1910-2013 Observation Band: 1929-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 193.7-S6 2nd: 193.7-S6 3rd: 195.4-SQ



Schedule E

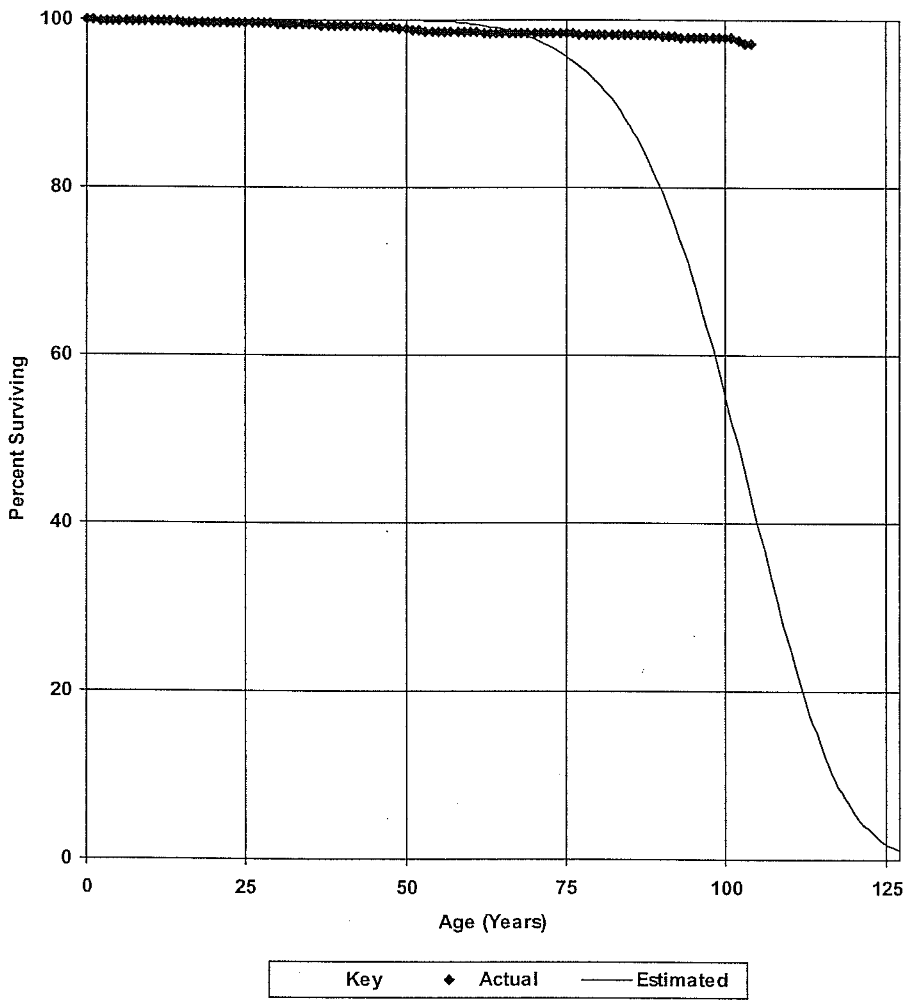
HYDRO ONE NETWORKS INC.

Transmission Lines

Account: STSTRCT Steel Structures

T-Cut: None
Placement Band: 1910-2013
Observation Band: 1929-2013
100.0-R5

Estimated Projection Life Curve



HYDRO ONE NETWORKS INC.

Transmission Lines

Account: UGCABLE Underground Cables (in Metres)

Placement Band: 1951 - 2009
Observation Band: 1999 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	18,700	0	0.00000	1.00000	1.00000
0.5	18,700	0	0.00000	1.00000	1.00000
1.5	18,700	0	0.00000	1.00000	1.00000
2.5	19,200	0	0.00000	1.00000	1.00000
3.5	19,200	0	0.00000	1.00000	1.00000
4.5	17,400	0	0.00000	1.00000	1.00000
5.5	25,100	0	0.00000	1.00000	1.00000
6.5	40,300	0	0.00000	1.00000	1.00000
7.5	44,900	0	0.00000	1.00000	1.00000
8.5	43,600	0	0.00000	1.00000	1.00000
9.5	46,600	0	0.00000	1.00000	1.00000
10.5	51,100	0	0.00000	1.00000	1.00000
11.5	55,300	0	0.00000	1.00000	1.00000
12.5	55,300	0	0.00000	1.00000	1.00000
13.5	45,000	0	0.00000	1.00000	1.00000
14.5	45,000	0	0.00000	1.00000	1.00000
15.5	45,000	0	0.00000	1.00000	1.00000
16.5	69,700	0	0.00000	1.00000	1.00000
17.5	73,100	0	0.00000	1.00000	1.00000
18.5	78,900	0	0.00000	1.00000	1.00000
19.5	78,900	0	0.00000	1.00000	1.00000
20.5	78,300	0	0.00000	1.00000	1.00000
21.5	68,900	0	0.00000	1.00000	1.00000
22.5	70,000	0	0.00000	1.00000	1.00000
23.5	79,400	0	0.00000	1.00000	1.00000
24.5	86,400	0	0.00000	1.00000	1.00000
25.5	97,000	0	0.00000	1.00000	1.00000
26.5	92,800	0	0.00000	1.00000	1.00000
27.5	105,200	0	0.00000	1.00000	1.00000
28.5	109,400	0	0.00000	1.00000	1.00000
29.5	110,700	0	0.00000	1.00000	1.00000
30.5	121,200	1,900	0.01568	0.98432	1.00000
31.5	95,900	0	0.00000	1.00000	0.98432
32.5	102,000	0	0.00000	1.00000	0.98432
33.5	99,800	0	0.00000	1.00000	0.98432
34.5	102,300	0	0.00000	1.00000	0.98432
35.5	89,900	0	0.00000	1.00000	0.98432

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: UGCABLE Underground Cables (in Metres)

Placement Band: 1951 - 2009
Observation Band: 1999 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	84,100	2,000	0.02378	0.97622	0.98432
37.5	95,600	0	0.00000	1.00000	0.96092
38.5	87,600	0	0.00000	1.00000	0.96092
39.5	87,400	0	0.00000	1.00000	0.96092
40.5	74,100	0	0.00000	1.00000	0.96092
41.5	86,100	0	0.00000	1.00000	0.96092
42.5	79,900	0	0.00000	1.00000	0.96092
43.5	79,500	1,400	0.01761	0.98239	0.96092
44.5	76,800	0	0.00000	1.00000	0.94399
45.5	73,300	3,400	0.04638	0.95362	0.94399
46.5	68,600	0	0.00000	1.00000	0.90021
47.5	64,600	0	0.00000	1.00000	0.90021
48.5	61,000	0	0.00000	1.00000	0.90021
49.5	58,500	800	0.01368	0.98632	0.90021
50.5	57,700	1,300	0.02253	0.97747	0.88790
51.5	56,400	0	0.00000	1.00000	0.86789
52.5	42,000	0	0.00000	1.00000	0.86789
53.5	40,600	0	0.00000	1.00000	0.86789
54.5	30,800	0	0.00000	1.00000	0.86789
55.5	29,000	13,000	0.44828	0.55172	0.86789
56.5	15,200	2,400	0.15789	0.84211	0.47884
57.5	9,000	0	0.00000	1.00000	0.40323
58.5	5,200	0	0.00000	1.00000	0.40323
59.5	5,200	0	0.00000	1.00000	0.40323
60.5	5,200	0	0.00000	1.00000	0.40323
61.5	5,200	2,400	0.46154	0.53846	0.40323
62.5	0	0	0.00000	1.00000	0.21712

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: UGCABLE Underground Cables (in Metres)

T-Cut: None

Placement Band: 1951-2009

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2003	85.1	116.6	L1.5*	1.84	99.7	S1*	1.89	72.3	R4*	1.87
2000-2004	76.9	101.8	L2*	4.21	67.2	R3*	5.24	59.2	R5*	3.99
2001-2005	70.7	80.0	L2*	3.41	65.6	S3*	2.74	63.1	R4*	2.46
2002-2006	78.5	89.0	L2*	2.03	74.8	S2*	1.88	133.2	SC*	1.92
2003-2007	72.9	72.4	L2*	3.25	65.5	S2*	1.96	132.7	SC*	5.93
2004-2008	73.5	74.1	L2*	3.04	68.3	S2*	2.48	139.2	SC*	7.72
2005-2009	57.3	72.8	L2*	3.76	65.7	S3*	3.20	66.9	S2*	3.32
2006-2010	62.6	85.1	L2*	5.01	69.4	S3*	4.68	68.2	R4*	4.46
2007-2011	71.5	87.3	L2*	3.59	72.7	S3*	3.17	72.1	S3*	3.07
2008-2012	84.7	119.8	L2*	3.05	82.0	S3*	3.97	73.6	S4*	2.43
2009-2013	18.6	57.1	L3*	17.48	41.8	R0.5*	30.01	50.2	R3*	17.31

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: UGCABLE Underground Cables (in Metres)

T-Cut: None

Placement Band: 1951-2009

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2013	21.7	65.0	L3 *	10.26	51.6	R2.5 *	14.37	54.3	R4 *	8.24
2001-2013	22.0	63.9	L3 *	10.71	50.7	R2 *	15.90	54.2	R4 *	8.77
2003-2013	21.9	62.4	L3 *	10.75	49.0	R1.5 *	17.83	54.0	R4 *	8.87
2005-2013	21.8	60.7	L3 *	10.80	47.6	R1.5 *	19.25	53.7	R4 *	9.13
2007-2013	22.6	59.2	L3 *	12.82	44.8	R1 *	24.18	52.7	R4 *	11.54
2009-2013	18.6	57.1	L3 *	17.48	41.8	R0.5 *	30.01	50.2	R3 *	17.31
2011-2013	20.1	52.5	S3 *	22.11	35.0	SC *	39.91	48.3	R2.5 *	20.26
2013-2013	2.2	42.5	S4 *	38.82	13.8	O4 *	71.91	40.2	R1 *	33.15

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: UGCABLE Underground Cables (in Metres)

T-Cut: None
Placement Band: 1951-2009
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2000	83.9	104.4	L1	4.11	172.0	R2 *	3.48	167.2	R1 *	3.61
1999-2002	80.9	104.8	L1.5 *	2.21	87.2	S1.5 *	2.17	66.4	R4 *	2.35
1999-2004	73.6	97.9	L2 *	3.70	71.5	R3 *	3.52	60.5	R4 *	3.18
1999-2006	74.9	89.8	L2 *	2.39	75.1	S2 *	2.45	71.4	R3 *	2.44
1999-2008	79.6	84.2	L2 *	1.88	72.3	S2 *	1.39	131.7	SC *	1.96
1999-2010	61.6	84.8	L2 *	4.11	70.3	S3 *	3.34	67.2	S3 *	3.15
1999-2012	77.1	93.1	L2 *	1.78	77.8	S2 *	1.17	79.3	S2 *	1.21
1999-2013	21.7	65.0	L3 *	10.26	51.6	R2.5 *	14.37	54.3	R4 *	8.24

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: UGCABLE Underground Cables (in Metres)

T-Cut: None

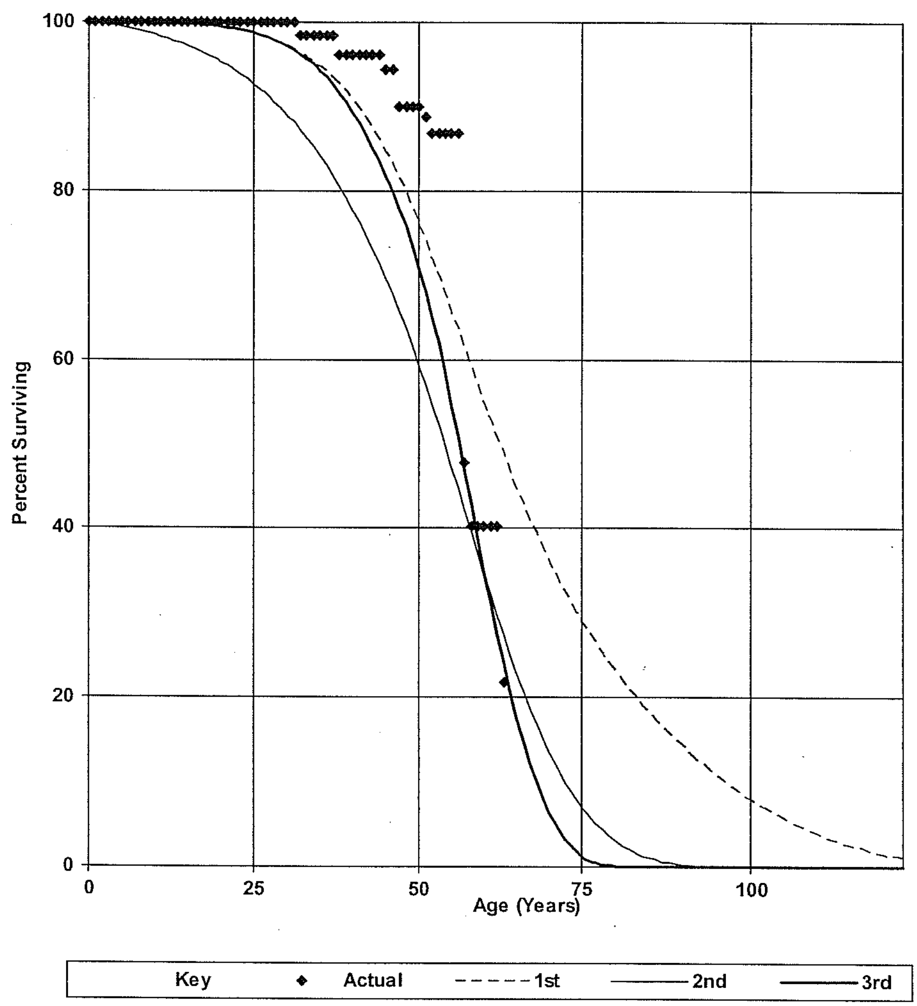
Placement Band: 1951-2009 Observation Band: 1999-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 65.0-L3 2nd: 51.6-R2.5 3rd: 54.3-R4



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: UGCABLE Underground Cables (in Metres)

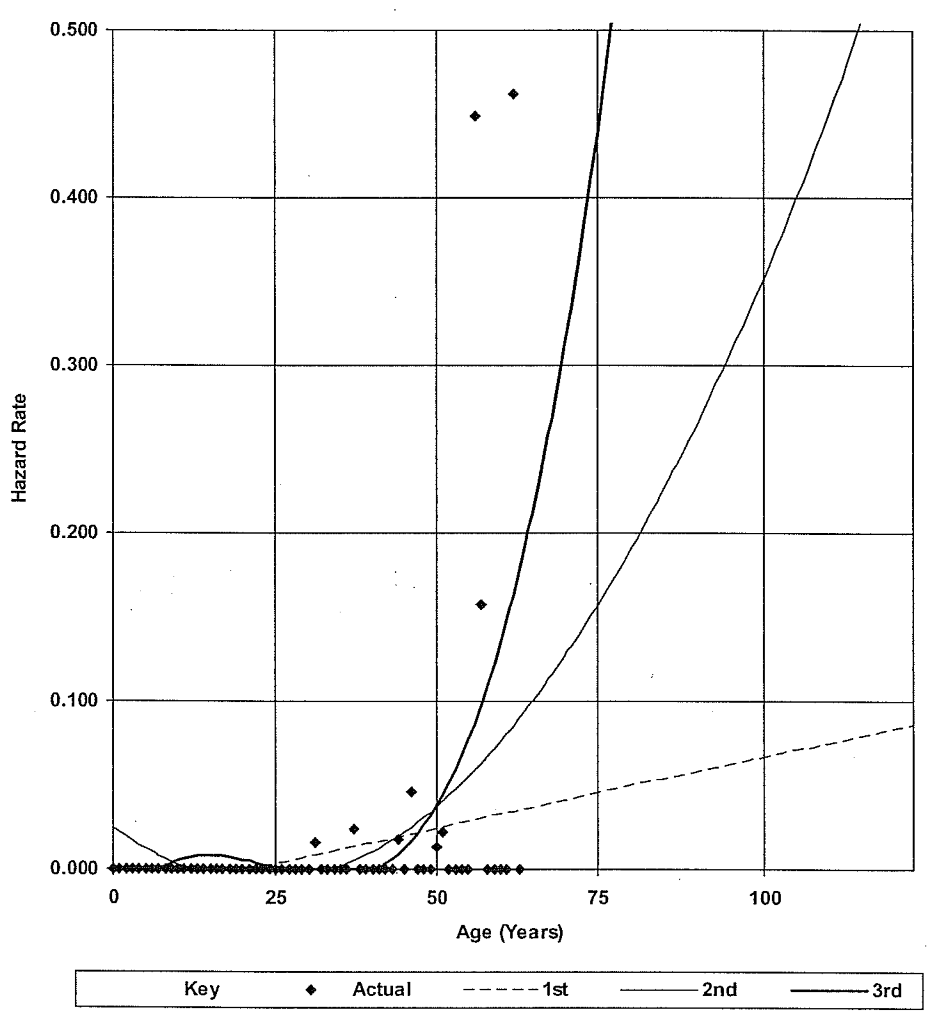
T-Cut: None

Placement Band: 1951-2009 Observation Band: 1999-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function 1st: 65.0-L3 2nd: 51.6-R2.5 3rd: 54.3-R4



Schedule E

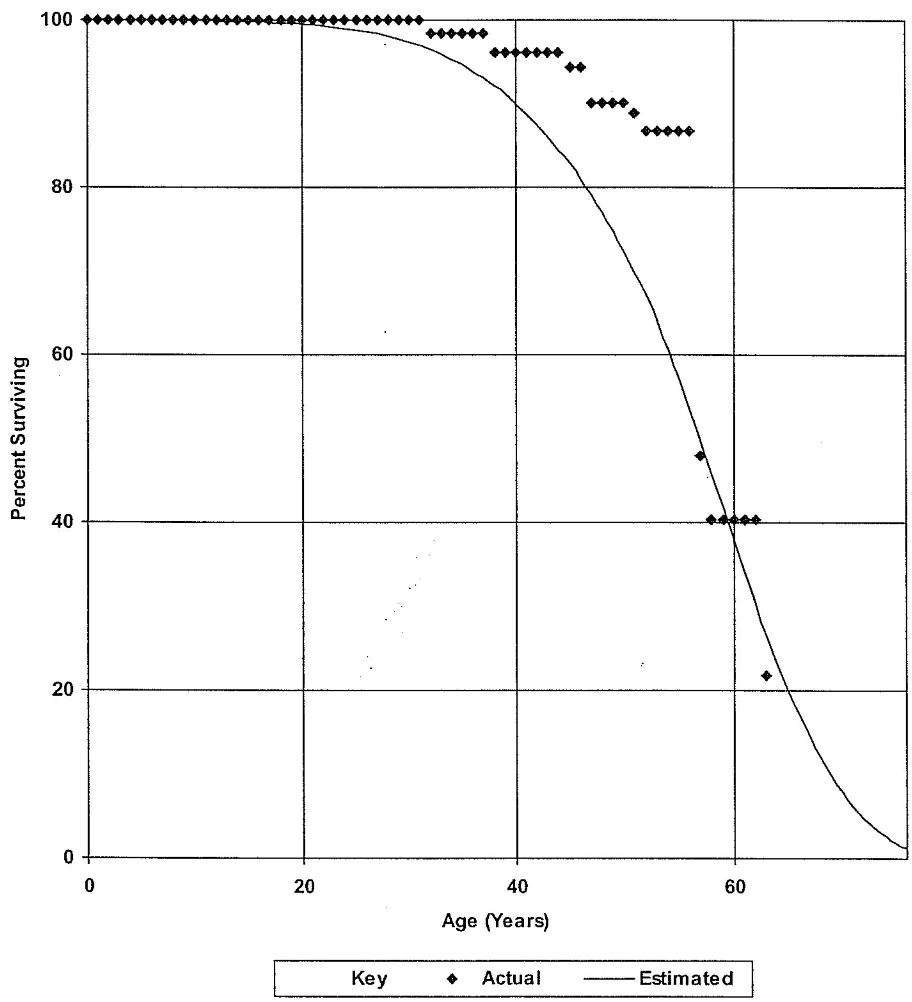
HYDRO ONE NETWORKS INC.

Transmission Lines

Account: UGCABLE Underground Cables (in Metres)

T-Cut: None
Placement Band: 1951-2009
Observation Band: 1999-2013
55.0-R4

Estimated Projection Life Curve



HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

Placement Band: 1910 - 2013
Observation Band: 1922 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	44,126	0	0.00000	1.00000	1.00000
0.5	44,173	7	0.00016	0.99984	1.00000
1.5	45,028	14	0.00031	0.99969	0.99984
2.5	44,728	13	0.00029	0.99971	0.99953
3.5	44,258	49	0.00111	0.99889	0.99924
4.5	43,797	48	0.00110	0.99890	0.99813
5.5	43,228	12	0.00028	0.99972	0.99704
6.5	42,628	44	0.00103	0.99897	0.99676
7.5	42,329	20	0.00047	0.99953	0.99573
8.5	42,024	10	0.00024	0.99976	0.99526
9.5	41,515	5	0.00012	0.99988	0.99503
10.5	39,595	3	0.00008	0.99992	0.99491
11.5	37,354	3	0.00008	0.99992	0.99483
12.5	37,055	1	0.00003	0.99997	0.99475
13.5	35,956	1	0.00003	0.99997	0.99473
14.5	35,195	0	0.00000	1.00000	0.99470
15.5	34,981	2	0.00006	0.99994	0.99470
16.5	34,703	1	0.00003	0.99997	0.99464
17.5	34,632	4	0.00012	0.99988	0.99461
18.5	34,598	6	0.00017	0.99983	0.99450
19.5	34,589	3	0.00009	0.99991	0.99432
20.5	34,586	1	0.00003	0.99997	0.99424
21.5	34,584	2	0.00006	0.99994	0.99421
22.5	34,558	30	0.00087	0.99913	0.99415
23.5	34,521	1	0.00003	0.99997	0.99329
24.5	34,516	16	0.00046	0.99954	0.99326
25.5	34,498	1	0.00003	0.99997	0.99280
26.5	34,482	244	0.00708	0.99292	0.99277
27.5	34,221	9	0.00026	0.99974	0.98575
28.5	34,135	241	0.00706	0.99294	0.98549
29.5	33,893	12	0.00035	0.99965	0.97853
30.5	33,881	431	0.01272	0.98728	0.97818
31.5	33,425	62	0.00185	0.99815	0.96574
32.5	33,007	10	0.00030	0.99970	0.96395
33.5	32,993	30	0.00091	0.99909	0.96366
34.5	32,879	29	0.00088	0.99912	0.96278
35.5	32,705	100	0.00306	0.99694	0.96193

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

Placement Band: 1910 - 2013
Observation Band: 1922 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	32,235	93	0.00289	0.99711	0.95899
37.5	31,484	59	0.00187	0.99813	0.95622
38.5	30,260	63	0.00208	0.99792	0.95443
39.5	30,094	47	0.00156	0.99844	0.95244
40.5	29,367	398	0.01355	0.98645	0.95096
41.5	28,150	124	0.00440	0.99560	0.93807
42.5	26,914	37	0.00137	0.99863	0.93394
43.5	26,790	79	0.00295	0.99705	0.93265
44.5	26,575	64	0.00241	0.99759	0.92990
45.5	25,896	467	0.01803	0.98197	0.92766
46.5	24,970	372	0.01490	0.98510	0.91093
47.5	24,437	278	0.01138	0.98862	0.89736
48.5	24,057	68	0.00283	0.99717	0.88715
49.5	23,558	109	0.00463	0.99537	0.88465
50.5	23,231	135	0.00581	0.99419	0.88055
51.5	22,927	427	0.01862	0.98138	0.87544
52.5	22,488	82	0.00365	0.99635	0.85913
53.5	22,406	533	0.02379	0.97621	0.85600
54.5	21,783	480	0.02204	0.97796	0.83564
55.5	20,266	181	0.00893	0.99107	0.81722
56.5	18,618	85	0.00457	0.99543	0.80992
57.5	18,230	151	0.00828	0.99172	0.80623
58.5	17,290	149	0.00862	0.99138	0.79955
59.5	16,985	176	0.01036	0.98964	0.79266
60.5	15,827	274	0.01731	0.98269	0.78444
61.5	15,060	187	0.01242	0.98758	0.77086
62.5	13,450	529	0.03933	0.96067	0.76129
63.5	11,632	36	0.00309	0.99691	0.73135
64.5	11,581	38	0.00328	0.99672	0.72909
65.5	10,376	52	0.00501	0.99499	0.72669
66.5	10,034	61	0.00608	0.99392	0.72305
67.5	9,878	97	0.00982	0.99018	0.71866
68.5	9,491	113	0.01191	0.98809	0.71160
69.5	9,378	182	0.01941	0.98059	0.70313
70.5	9,004	206	0.02288	0.97712	0.68948
71.5	8,676	120	0.01383	0.98617	0.67371
72.5	8,510	81	0.00952	0.99048	0.66439

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

Placement Band: 1910 - 2013
Observation Band: 1922 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	7,922	76	0.00959	0.99041	0.65806
74.5	6,954	102	0.01467	0.98533	0.65175
75.5	6,851	29	0.00423	0.99577	0.64219
76.5	4,924	6	0.00122	0.99878	0.63947
77.5	3,965	22	0.00555	0.99445	0.63869
78.5	3,942	1	0.00025	0.99975	0.63515
79.5	3,752	704	0.18763	0.81237	0.63499
80.5	3,002	2	0.00067	0.99933	0.51584
81.5	2,995	1	0.00033	0.99967	0.51550
82.5	2,953	1	0.00034	0.99966	0.51533
83.5	2,280	0	0.00000	1.00000	0.51515
84.5	2,265	0	0.00000	1.00000	0.51515
85.5	1,592	0	0.00000	1.00000	0.51515
86.5	1,586	20	0.01261	0.98739	0.51515
87.5	1,158	18	0.01554	0.98446	0.50866
88.5	1,062	0	0.00000	1.00000	0.50075
89.5	620	0	0.00000	1.00000	0.50075
90.5	606	0	0.00000	1.00000	0.50075
91.5	566	1	0.00177	0.99823	0.50075
92.5	563	2	0.00355	0.99645	0.49987
93.5	402	0	0.00000	1.00000	0.49809
94.5	402	2	0.00498	0.99502	0.49809
95.5	400	0	0.00000	1.00000	0.49561
96.5	400	0	0.00000	1.00000	0.49561
97.5	315	3	0.00952	0.99048	0.49561
98.5	302	0	0.00000	1.00000	0.49089
99.5	201	0	0.00000	1.00000	0.49089
100.5	201	0	0.00000	1.00000	0.49089
101.5	201	1	0.00498	0.99502	0.49089
102.5	200	0	0.00000	1.00000	0.48845
103.5	0	0	0.00000	1.00000	0.48845

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None
Placement Band: 1910-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1922-1926	99.2	117.1	S0 *	0.16	70.9	S1.5 *	0.12	196.9	SQ *	0.23
1923-1927	99.5	151.1	R1.5 *	0.10	88.2	S1.5 *	0.10	197.9	SQ *	0.12
1924-1928	99.7	159.0	R2 *	0.07	118.4	S1 *	0.07	198.0	SQ *	0.14
1925-1929	99.9	198.5	SQ *	0.03	198.7	SQ *	0.04	57.5	S3 *	0.02
1926-1930	99.9	198.7	SQ *	0.04	198.7	SQ *	0.04	58.1	S3 *	0.04
1927-1931	99.8	198.7	SQ *	0.05	198.8	SQ *	0.05	60.8	S3 *	0.05
1928-1932	99.9	198.8	SQ *	0.02	198.8	SQ *	0.02	63.3	S3 *	0.02
1929-1933	99.9	198.8	SQ *	0.02	198.8	SQ *	0.02	66.7	S3 *	0.02
1930-1934	100.0				No Retirements					
1931-1935	100.0				No Retirements					
1932-1936	100.0				No Retirements					
1933-1937	100.0				No Retirements					
1934-1938	100.0				No Retirements					
1935-1939	100.0				No Retirements					
1936-1940	100.0				No Retirements					
1937-1941	99.8	194.7	S6 *	0.05	198.8	SQ *	0.04	198.8	SQ *	0.04
1938-1942	99.9	196.4	SQ	0.03	198.7	SQ *	0.02	147.5	S3 *	0.02
1939-1943	99.9	197.0	SQ	0.03	198.8	SQ *	0.02	154.1	S3 *	0.02
1940-1944	99.9	197.5	S6	0.03	198.8	SQ *	0.03	169.5	R4 *	0.03
1941-1945	99.9	198.2	SQ	0.02	198.8	SQ *	0.02	189.0	R5 *	0.02
1942-1946	100.0	198.9	SQ *	0.02	188.7	R5 *	0.02	198.3	SQ *	0.02
1943-1947	100.0				No Retirements					
1944-1948	99.9	198.9	SQ *	0.07	165.7	R3 *	0.04	198.7	SQ *	0.02
1945-1949	99.8	198.8	SQ *	0.06	187.5	R4	0.05	198.7	SQ *	0.04
1946-1950	99.6	194.9	S6	0.09	198.2	SQ *	0.06	198.1	SQ *	0.07
1947-1951	98.4	194.7	S6	0.16	118.1	S2	0.24	81.5	S3 *	0.24
1948-1952	98.2	194.5	SQ	0.24	130.0	S2	0.24	85.0	S3 *	0.25
1949-1953	97.8	188.3	R4	0.37	144.8	S1.5	0.36	92.2	S3	0.36
1950-1954	97.5	191.7	R5	0.65	146.7	R2.5	0.64	100.4	S3	0.64
1951-1955	99.0	195.3	SQ	0.17	139.1	S2	0.13	114.5	S3	0.12
1952-1956	99.2	186.3	R4 *	0.11	164.3	R2.5	0.13	197.3	SQ *	0.11
1953-1957	98.8	185.0	R4 *	0.13	147.1	R2.5	0.19	166.2	R2	0.19
1954-1958	98.6	189.8	R5	0.21	150.2	R2.5	0.18	137.6	S2	0.18
1955-1959	99.0	190.1	R5 *	0.12	159.5	R2.5	0.11	134.0	R3	0.11
1956-1960	98.9	190.9	R5 *	0.14	165.2	R2.5	0.12	154.3	R2.5	0.12
1957-1961	99.6	198.5	SQ *	0.08	179.0	R4	0.06	116.6	S3 *	0.06
1958-1962	99.9	198.6	SQ *	0.05	198.7	SQ *	0.05	136.3	S3 *	0.06
1959-1963	98.5	174.2	R2.5 *	0.41	127.6	S2 *	0.49	192.9	S6 *	0.54

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None
Placement Band: 1910-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1960-1964	96.8	175.4	R3*	0.89	134.0	S2	0.84	194.3	SQ*	0.74
1961-1965	97.9	177.0	R3*	0.43	140.7	S1.5	0.44	194.9	SQ*	0.41
1962-1966	96.8	175.6	R3*	0.57	143.6	S1.5	0.54	194.5	S6*	0.45
1963-1967	98.1	174.6	R3*	0.28	152.8	R2*	0.30	194.9	SQ*	0.39
1964-1968	99.2	194.7	S6*	0.13	190.8	R5*	0.13	194.3	SQ*	0.13
1965-1969	99.1	195.1	S6*	0.22	192.8	R5*	0.22	197.6	S6*	0.22
1966-1970	98.5	195.1	SQ	0.39	186.4	R4	0.36	197.6	S6*	0.35
1967-1971	99.4	197.4	SQ	0.23	192.0	R5	0.21	198.4	SQ*	0.20
1968-1972	99.5	196.5	S6	0.11	188.2	R4	0.08	198.2	SQ*	0.08
1969-1973	99.6	196.7	S6	0.05	191.6	R5	0.05	198.2	SQ*	0.05
1970-1974	99.4	197.0	SQ	0.12	194.4	S6	0.12	198.2	SQ*	0.11
1971-1975	99.5	197.6	S6	0.09	198.2	SQ*	0.10	198.4	SQ*	0.10
1972-1976	99.1	195.5	SQ	0.10	197.6	S6*	0.06	182.8	R4*	0.07
1973-1977	99.5	197.1	SQ*	0.22	197.7	SQ*	0.17	161.7	R4*	0.17
1974-1978	99.5	197.3	SQ*	0.18	197.8	SQ*	0.14	160.8	R4*	0.14
1975-1979	99.5	197.5	S6*	0.22	197.7	SQ*	0.19	168.8	R4*	0.19
1976-1980	99.4	197.6	S6*	0.16	197.8	SQ*	0.13	165.2	R4*	0.13
1977-1981	99.8	198.6	SQ*	0.03	196.2	SQ	0.03	198.6	SQ*	0.02
1978-1982	99.6	198.1	SQ*	0.04	196.9	SQ	0.04	198.3	SQ*	0.04
1979-1983	99.5	198.2	SQ*	0.11	196.8	S6	0.11	198.2	SQ*	0.09
1980-1984	99.8	197.6	S6	0.05	198.6	SQ*	0.03	198.6	SQ*	0.02
1981-1985	99.7	197.8	SQ	0.04	198.6	SQ*	0.03	198.6	SQ*	0.03
1982-1986	99.5	196.5	S6	0.09	198.2	SQ*	0.07	198.2	SQ*	0.07
1983-1987	99.6	196.3	SQ	0.13	198.2	SQ*	0.08	198.2	SQ*	0.07
1984-1988	99.6	196.6	S6	0.15	198.2	SQ*	0.09	198.2	SQ*	0.08
1985-1989	99.6	195.5	S6	0.21	198.0	SQ*	0.16	198.0	SQ*	0.15
1986-1990	99.5	194.9	S6	0.28	197.8	SQ*	0.21	197.8	SQ*	0.20
1987-1991	99.3	195.5	S6*	0.16	198.0	SQ*	0.14	194.5	S6*	0.15
1988-1992	99.0	196.7	S6*	0.17	198.3	SQ*	0.18	190.1	R5*	0.17
1989-1993	99.4	196.9	SQ*	0.11	198.4	SQ*	0.12	189.8	R5*	0.11
1990-1994	99.4	197.6	S6*	0.10	198.5	SQ*	0.11	185.1	R4*	0.10
1991-1995	99.4	198.0	SQ*	0.12	198.0	SQ*	0.12	186.0	R5*	0.11
1992-1996	94.5	172.5	R3*	0.89	134.8	R3*	1.98	119.6	R4*	0.90
1993-1997	91.2	170.0	R2.5*	2.55	141.6	S2*	1.79	133.4	S3	2.29
1994-1998	87.7	138.2	S1*	1.89	126.4	S1.5*	2.05	166.6	R1*	5.68
1995-1999	77.9	106.3	L1.5*	7.00	150.5	SC*	5.56	153.9	R0.5*	4.96
1996-2000	19.8	77.0	S1.5*	11.13	55.2	SC	23.02	65.1	R2*	12.38
1997-2001	14.8	76.9	L2*	10.74	60.3	R0.5	15.76	62.7	R1*	12.10

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None

Placement Band: 1910-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1998-2002	8.4	51.1	L1	9.58	49.7	L0.5	10.80	48.7	L0.5 *	11.47
1999-2003	5.1	41.3	L0	13.38	45.6	L0.5 *	10.01	42.6	L0.5 *	11.75
2000-2004	13.9	45.0	L0	13.51	48.0	L0.5 *	12.06	43.7	L0.5 *	14.94
2001-2005	26.4	46.2	O2	16.18	62.3	O4 *	14.73	68.5	O3 *	10.03
2002-2006	27.0	44.6	O2	17.95	57.3	O3 *	18.02	63.0	O3 *	13.45
2003-2007	41.1	65.3	O2	12.44	86.8	O4 *	13.54	95.0	O3 *	8.74
2004-2008	37.7	79.1	L0.5	5.97	83.9	L0	6.24	116.3	SC *	2.23
2005-2009	32.0	72.3	L0.5	8.43	79.2	O2 *	9.07	108.5	O3 *	2.72
2006-2010	34.3	69.8	L0.5	9.61	80.4	O3 *	10.58	102.0	O3 *	3.69
2007-2011	36.8	71.5	L0.5	8.94	83.9	O3 *	10.31	103.4	O3 *	3.42
2008-2012	46.6	83.2	L1	7.17	100.2	O3 *	8.96	118.3	SC *	3.04
2009-2013	56.6	101.5	L1	4.84	126.8	SC *	6.43	136.9	SC *	2.49

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None

Placement Band: 1910-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1922-2013	48.8	95.3	L1.5*	3.03	90.4	S1 *	3.61	124.8	SC *	1.76
1924-2013	48.8	95.3	L1.5*	3.02	90.4	S1 *	3.61	124.8	SC *	1.76
1926-2013	48.8	95.3	L1.5*	3.02	90.4	S1 *	3.60	124.8	SC *	1.76
1928-2013	48.8	95.3	L1.5*	3.02	90.4	S1 *	3.60	124.8	SC *	1.76
1930-2013	48.8	95.3	L1.5*	3.02	90.4	S1 *	3.60	124.8	SC *	1.75
1932-2013	48.8	95.3	L1.5*	3.01	90.5	S1 *	3.60	124.8	SC *	1.75
1934-2013	48.8	95.3	L1.5*	3.01	90.5	S1 *	3.59	124.8	SC *	1.75
1936-2013	48.8	95.3	L1.5*	3.01	90.5	S1 *	3.59	124.8	SC *	1.75
1938-2013	48.8	95.2	L1.5*	3.00	90.5	S1 *	3.59	124.8	SC *	1.75
1940-2013	48.8	95.2	L1.5*	3.00	90.5	S1 *	3.58	124.8	SC *	1.75
1942-2013	48.8	95.2	L1.5*	2.99	90.5	S1 *	3.57	124.9	SC *	1.74
1944-2013	48.8	95.2	L1.5*	2.98	90.5	S1 *	3.56	124.9	SC *	1.74
1946-2013	48.8	95.1	L1.5*	2.97	90.5	S1 *	3.55	124.8	SC *	1.74
1948-2013	48.7	95.1	L1.5*	2.96	90.5	S1 *	3.54	124.8	SC *	1.73
1950-2013	48.7	95.1	L1.5*	2.96	90.5	S1 *	3.53	124.8	SC *	1.73
1952-2013	48.7	95.0	L1.5*	2.95	90.6	S1 *	3.52	124.8	SC *	1.73
1954-2013	48.7	94.9	L1.5*	2.95	90.6	S1 *	3.50	124.8	SC *	1.72
1956-2013	48.6	94.8	L1.5*	2.93	90.6	S1 *	3.47	124.8	SC *	1.71
1958-2013	48.5	94.7	L1.5*	2.92	90.7	S1 *	3.45	124.7	SC *	1.70
1960-2013	48.5	94.5	L1.5*	2.91	90.7	S1 *	3.42	124.6	SC *	1.70
1962-2013	48.4	94.4	L1.5*	2.90	90.7	S1 *	3.38	124.5	SC *	1.69
1964-2013	48.3	94.2	L1.5*	2.90	90.7	S1 *	3.36	124.4	SC *	1.68
1966-2013	48.1	94.0	L1.5*	2.89	90.7	S1 *	3.33	124.1	SC *	1.67
1968-2013	47.9	93.7	L1.5*	2.87	90.6	L2 *	3.27	123.9	SC *	1.66
1970-2013	47.6	93.3	L1.5*	2.87	90.5	L2 *	3.23	123.5	SC *	1.64
1972-2013	47.4	92.8	L1.5*	2.89	90.4	L2 *	3.20	123.1	SC *	1.63
1974-2013	47.1	92.2	L1.5*	2.97	90.3	L2 *	3.20	122.6	SC *	1.62
1976-2013	46.7	91.5	L1.5*	3.01	90.2	L1.5 *	3.16	121.9	SC *	1.61
1978-2013	46.2	90.7	L1.5*	3.07	90.1	L1.5 *	3.14	121.2	SC *	1.61
1980-2013	45.5	89.6	L1.5*	3.06	90.0	L1.5 *	3.02	120.0	SC *	1.57
1982-2013	44.6	88.3	L1.5*	3.09	89.8	L1.5 *	2.94	118.6	SC *	1.54
1984-2013	43.4	86.8	L1.5*	3.11	89.6	L1 *	2.82	116.9	SC *	1.51
1986-2013	42.0	84.8	L1*	3.17	89.4	L1 *	2.70	114.8	L0 *	1.50
1988-2013	40.6	82.4	L1	3.43	89.4	L0.5 *	2.72	112.2	O3 *	1.53
1990-2013	38.8	79.6	L1	3.80	89.8	O2 *	2.80	109.0	O3 *	1.59
1992-2013	36.5	76.2	L0.5	4.52	89.8	O2 *	3.34	104.9	O3 *	1.90
1994-2013	34.4	72.4	L0.5	5.54	88.4	O3 *	4.22	99.9	O3 *	2.55
1996-2013	31.4	68.2	L0.5	6.34	85.2	O3 *	5.02	93.7	O3 *	3.27

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None

Placement Band: 1910-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1998-2013	28.4	63.8	L0	7.35	80.8	O3 *	6.20	86.7	O3 *	4.48
2000-2013	26.8	62.7	L0	6.43	78.2	O3 *	5.59	82.9	O3 *	4.26
2002-2013	32.0	62.2	L0	10.25	80.7	O4 *	10.31	85.8	O3 *	7.04
2004-2013	52.4	89.0	L0.5	7.47	108.9	O3 *	7.95	125.9	SC *	2.76
2006-2013	49.5	84.5	L0.5	8.10	104.7	O3 *	8.91	119.4	SC *	3.72
2008-2013	52.9	91.2	L1	6.67	112.0	O3 *	8.26	127.5	SC *	3.03
2010-2013	58.1	111.5	L1	3.81	137.2	SC *	4.23	143.6	SC *	2.85
2012-2013	88.3	181.5	R4 *	3.26	164.5	R3 *	3.23	182.9	R3 *	3.12

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None
Placement Band: 1910-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1922-1923	99.5	94.5	L1 *	0.33	50.5	S1.5 *	0.20	196.5	SQ *	0.40
1922-1925	99.0	100.5	L1 *	0.23	54.0	S1.5 *	0.13	195.9	SQ *	0.22
1922-1927	99.2	132.3	S0 *	0.13	96.5	S1 *	0.12	197.2	SQ *	0.16
1922-1929	99.4	155.1	R1.5 *	0.10	197.4	SQ *	0.09	197.7	SQ *	0.06
1922-1931	99.5	171.4	R2.5 *	0.13	198.1	SQ *	0.12	198.1	SQ *	0.09
1922-1933	99.6	181.7	R4 *	0.08	198.4	SQ *	0.07	198.4	SQ *	0.06
1922-1935	99.8	188.3	R4	0.05	198.6	SQ *	0.03	198.6	SQ *	0.03
1922-1937	99.9	192.5	R5	0.04	198.7	SQ *	0.02	198.7	SQ *	0.02
1922-1939	99.9	194.6	S6	0.03	198.7	SQ *	0.01	191.5	R5 *	0.01
1922-1941	99.8	193.3	S6	0.04	198.7	SQ *	0.02	198.7	SQ *	0.02
1922-1943	99.9	195.7	S6	0.03	198.7	SQ *	0.02	145.9	S3 *	0.01
1922-1945	99.9	196.9	SQ	0.03	198.8	SQ *	0.01	145.4	S3 *	0.01
1922-1947	99.9	197.7	SQ	0.02	198.8	SQ *	0.01	148.1	S3 *	0.01
1922-1949	99.9	198.1	SQ	0.02	198.8	SQ *	0.01	198.8	SQ *	0.01
1922-1951	98.8	193.5	S6	0.14	145.9	R2.5	0.18	86.1	S3 *	0.20
1922-1953	98.7	192.3	R5	0.19	158.5	R2.5	0.16	99.2	S3	0.14
1922-1955	99.0	194.4	SQ	0.15	169.2	R3	0.11	116.8	S3	0.10
1922-1957	98.5	190.0	R5	0.14	147.8	R2.5	0.09	106.3	S3	0.10
1922-1959	98.6	192.3	R5	0.20	161.7	R2.5	0.11	120.7	S3	0.09
1922-1961	99.1	194.0	S6	0.08	171.7	R3	0.05	142.1	R3	0.05
1922-1963	98.2	184.3	R4 *	0.29	136.6	S2	0.24	134.7	S2	0.24
1922-1965	98.5	187.1	R4 *	0.23	148.7	R2.5	0.21	189.9	R5 *	0.19
1922-1967	98.6	187.6	R4 *	0.16	155.1	R2.5	0.19	194.0	SQ *	0.16
1922-1969	98.8	189.7	R5 *	0.14	165.2	R2.5	0.16	196.3	SQ *	0.11
1922-1971	98.9	191.1	R5	0.14	172.1	R3	0.17	196.9	SQ *	0.11
1922-1973	99.0	191.8	R5	0.13	177.3	R3	0.16	197.2	SQ *	0.10
1922-1975	99.1	193.0	S6	0.11	183.8	R4	0.14	197.5	SQ *	0.07
1922-1977	99.2	192.9	S6	0.11	192.5	R5	0.12	197.5	S6 *	0.06
1922-1979	99.3	194.1	S6	0.11	195.1	SQ	0.10	197.7	SQ *	0.05
1922-1981	99.3	194.9	S6	0.10	197.1	SQ *	0.08	197.8	SQ *	0.04
1922-1983	99.3	195.1	SQ	0.10	197.4	SQ *	0.07	197.8	SQ *	0.04
1922-1985	99.4	195.7	S6	0.09	197.7	SQ *	0.06	197.9	SQ *	0.03
1922-1987	99.3	195.3	SQ	0.13	197.7	SQ *	0.07	197.8	SQ *	0.05
1922-1989	99.4	195.5	S6	0.12	197.7	SQ *	0.07	197.8	SQ *	0.05
1922-1991	99.1	195.6	S6	0.10	197.7	SQ *	0.07	197.8	SQ *	0.08
1922-1993	99.2	196.1	SQ	0.09	197.8	SQ *	0.06	197.9	SQ *	0.07
1922-1995	99.2	196.4	SQ	0.08	197.9	SQ *	0.06	197.9	SQ *	0.07
1922-1997	95.7	189.5	R5 *	0.80	171.4	R3	0.53	145.4	S3	0.48

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None

Placement Band: 1910-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1922-1999	89.9	156.6	R2 *	1.08	138.0	S1.5 *	1.55	181.2	R3 *	0.95
1922-2001	41.2	125.7	S0.5 *	12.63	94.5	S3 *	9.19	86.0	R4 *	7.18
1922-2003	34.2	95.3	L2 *	8.16	85.0	S2	6.10	83.4	S2 *	5.88
1922-2005	44.3	97.1	L1.5 *	5.08	87.4	S1.5 *	3.87	88.1	S1.5 *	3.89
1922-2007	45.0	95.5	L1.5 *	3.80	87.1	S1.5 *	3.10	100.3	L1.5 *	2.97
1922-2009	44.3	92.8	L1.5 *	2.92	85.9	S1.5 *	2.98	107.1	L0.5 *	2.17
1922-2011	46.5	92.3	L1.5 *	2.89	86.7	S1.5 *	3.63	115.8	L0 *	2.02
1922-2013	48.8	95.3	L1.5 *	3.03	90.4	S1 *	3.61	124.8	SC *	1.76

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None

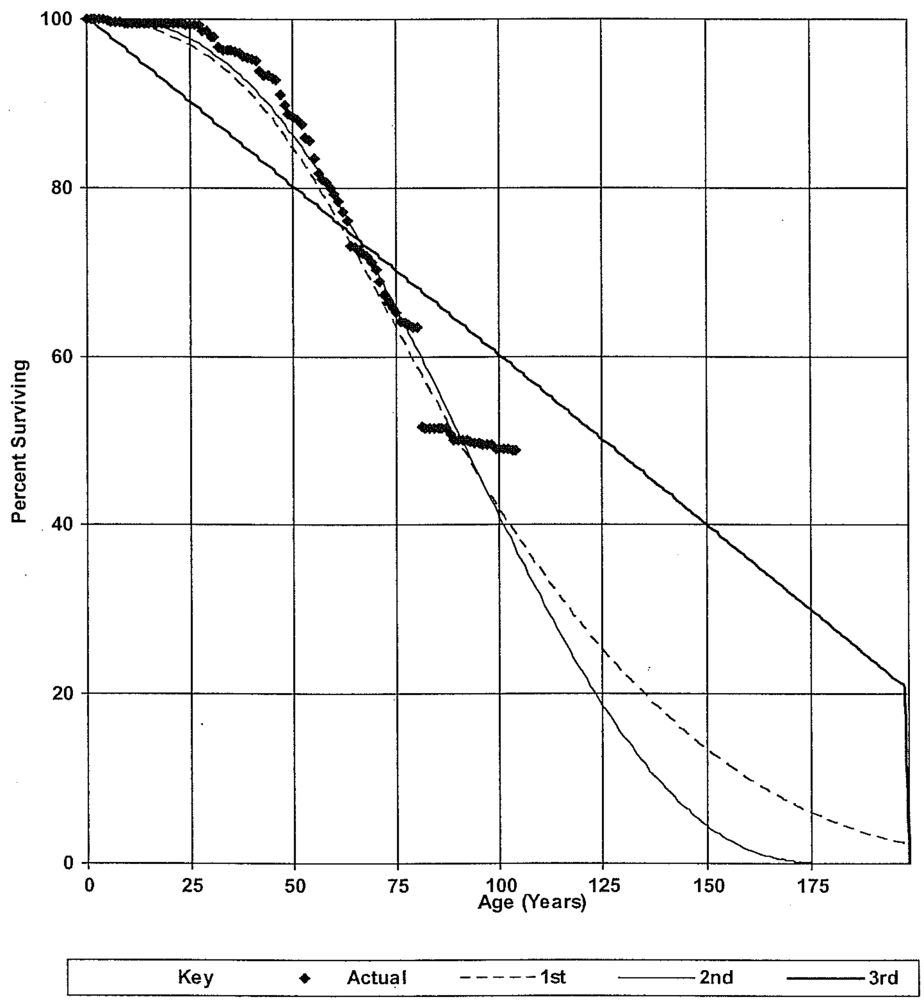
Placement Band: 1910-2013 Observation Band: 1922-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 95.3-L1.5 2nd: 90.4-S1 3rd: 124.8-SC



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

T-Cut: None

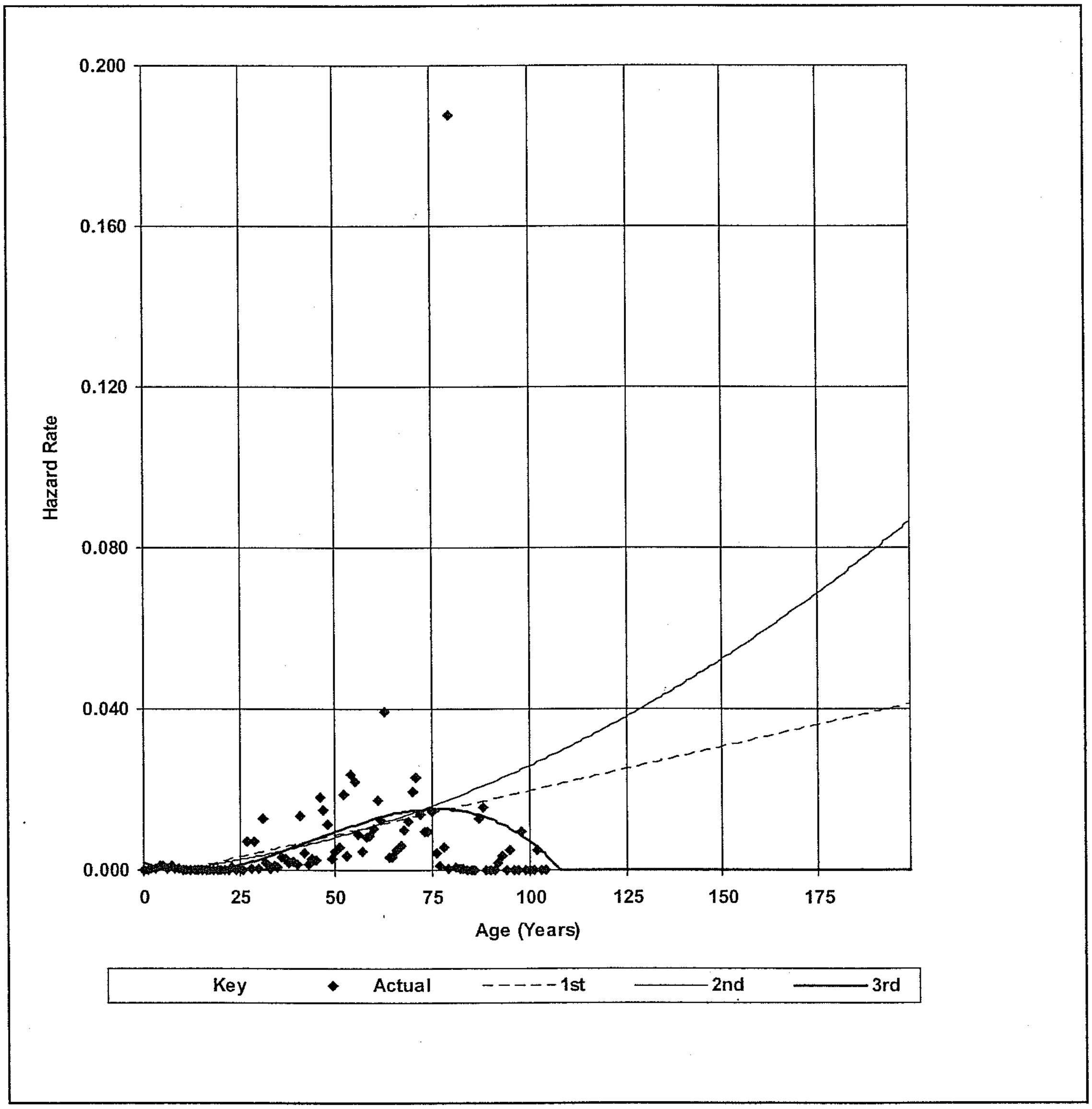
Placement Band: 1910-2013 Observation Band: 1922-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 95.3-L1.5 2nd: 90.4-S1 3rd: 124.8-SC



Schedule E

HYDRO ONE NETWORKS INC.

Transmission Lines

Account: WDPOLES Wood Poles

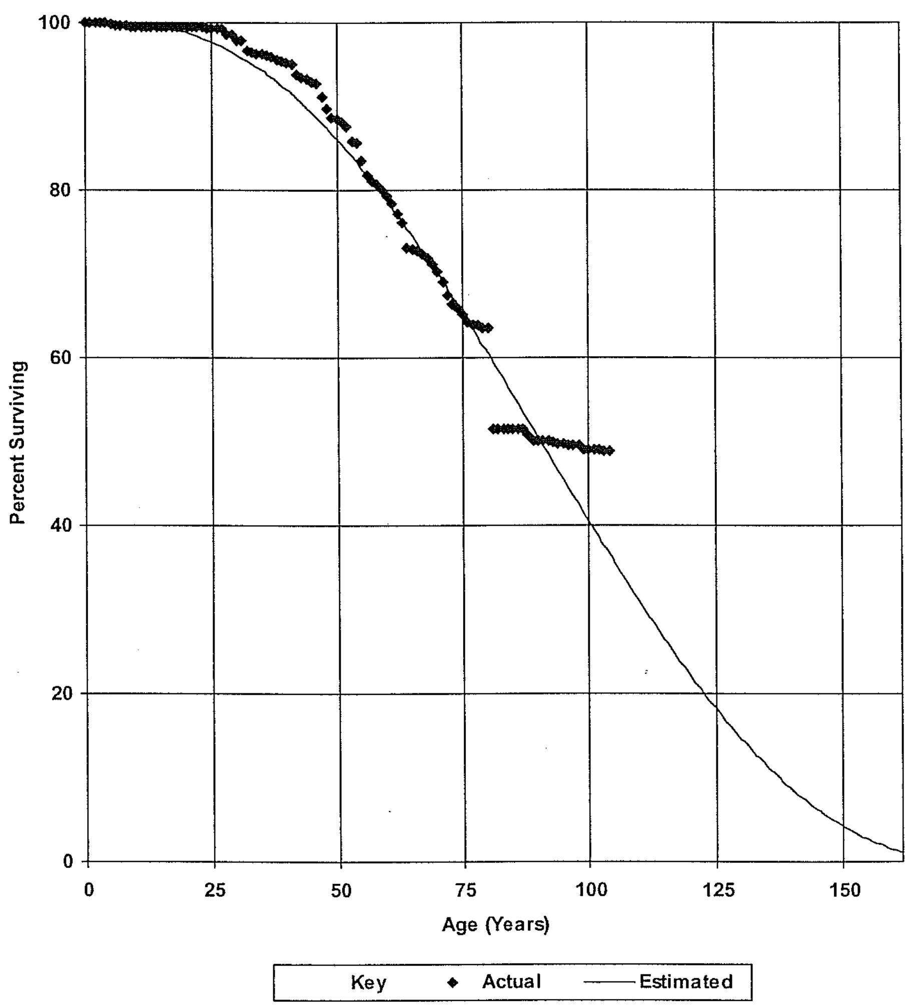
T-Cut: None

Placement Band: 1910-2013

Observation Band: 1922-2013

Estimated Projection Life Curve

90.0-S1



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

Placement Band: 1936 - 2013
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	501	4	0.00798	0.99202	1.00000
0.5	604	4	0.00662	0.99338	0.99202
1.5	855	4	0.00468	0.99532	0.98545
2.5	1,075	1	0.00093	0.99907	0.98084
3.5	1,249	3	0.00240	0.99760	0.97992
4.5	1,366	1	0.00073	0.99927	0.97757
5.5	1,629	0	0.00000	1.00000	0.97685
6.5	1,739	6	0.00345	0.99655	0.97685
7.5	1,772	4	0.00226	0.99774	0.97348
8.5	1,799	8	0.00445	0.99555	0.97129
9.5	1,839	9	0.00489	0.99511	0.96697
10.5	1,961	8	0.00408	0.99592	0.96223
11.5	2,056	19	0.00924	0.99076	0.95831
12.5	2,104	22	0.01046	0.98954	0.94945
13.5	2,225	5	0.00225	0.99775	0.93953
14.5	2,285	3	0.00131	0.99869	0.93741
15.5	2,348	22	0.00937	0.99063	0.93618
16.5	2,369	14	0.00591	0.99409	0.92741
17.5	2,362	20	0.00847	0.99153	0.92193
18.5	2,368	20	0.00845	0.99155	0.91412
19.5	2,379	17	0.00715	0.99285	0.90640
20.5	2,358	25	0.01060	0.98940	0.89993
21.5	2,326	20	0.00860	0.99140	0.89039
22.5	2,186	28	0.01281	0.98719	0.88273
23.5	2,051	35	0.01706	0.98294	0.87142
24.5	1,960	22	0.01122	0.98878	0.85655
25.5	1,934	23	0.01189	0.98811	0.84694
26.5	1,807	17	0.00941	0.99059	0.83687
27.5	1,840	17	0.00924	0.99076	0.82899
28.5	1,888	13	0.00689	0.99311	0.82133
29.5	1,896	14	0.00738	0.99262	0.81568
30.5	1,886	10	0.00530	0.99470	0.80966
31.5	1,838	35	0.01904	0.98096	0.80536
32.5	1,836	23	0.01253	0.98747	0.79003
33.5	1,840	18	0.00978	0.99022	0.78013
34.5	1,777	16	0.00900	0.99100	0.77250
35.5	1,746	9	0.00515	0.99485	0.76554

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

Placement Band: 1936 - 2013
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	1,721	26	0.01511	0.98489	0.76160
37.5	1,640	20	0.01220	0.98780	0.75009
38.5	1,563	25	0.01599	0.98401	0.74094
39.5	1,452	21	0.01446	0.98554	0.72909
40.5	1,396	23	0.01648	0.98352	0.71855
41.5	1,275	29	0.02275	0.97725	0.70671
42.5	1,192	12	0.01007	0.98993	0.69063
43.5	1,090	35	0.03211	0.96789	0.68368
44.5	948	19	0.02004	0.97996	0.66173
45.5	883	34	0.03851	0.96149	0.64847
46.5	751	9	0.01198	0.98802	0.62350
47.5	703	16	0.02276	0.97724	0.61602
48.5	653	15	0.02297	0.97703	0.60200
49.5	589	47	0.07980	0.92020	0.58818
50.5	518	17	0.03282	0.96718	0.54124
51.5	461	15	0.03254	0.96746	0.52348
52.5	412	13	0.03155	0.96845	0.50645
53.5	387	14	0.03618	0.96382	0.49047
54.5	352	13	0.03693	0.96307	0.47272
55.5	333	12	0.03604	0.96396	0.45526
56.5	292	13	0.04452	0.95548	0.43886
57.5	258	14	0.05426	0.94574	0.41932
58.5	242	11	0.04545	0.95455	0.39657
59.5	222	11	0.04955	0.95045	0.37854
60.5	199	5	0.02513	0.97487	0.35978
61.5	167	7	0.04192	0.95808	0.35074
62.5	142	6	0.04225	0.95775	0.33604
63.5	125	7	0.05600	0.94400	0.32184
64.5	108	4	0.03704	0.96296	0.30382
65.5	65	2	0.03077	0.96923	0.29257
66.5	42	2	0.04762	0.95238	0.28357
67.5	28	0	0.00000	1.00000	0.27006
68.5	23	4	0.17391	0.82609	0.27006
69.5	15	2	0.13333	0.86667	0.22309
70.5	11	0	0.00000	1.00000	0.19335
71.5	8	0	0.00000	1.00000	0.19335
72.5	5	0	0.00000	1.00000	0.19335

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

Placement Band: 1936 - 2013
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	0	0	0.00000	1.00000	0.19335

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

T-Cut: None
Placement Band: 1936-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-1985	95.2	167.7	R2*	0.66	119.2	S1.5	0.57	73.4	R4 *	0.51
1982-1986	95.8	166.2	R2*	0.71	118.9	S2 *	0.67	82.9	S3 *	0.64
1983-1987	94.6	186.4	R4	1.67	96.5	S2 *	1.04	192.4	SQ *	0.87
1984-1988	86.5	117.7	S0*	2.87	76.3	S2	2.06	78.7	S1.5	2.02
1985-1989	86.8	114.7	S0	3.42	76.9	S1.5	2.71	133.7	SC *	2.50
1986-1990	57.7	111.4	L1	5.99	75.3	R2	4.82	69.9	R2.5	4.87
1987-1991	25.6	85.8	L1*	8.84	79.0	S0.5	8.56	141.5	SC *	8.42
1988-1992	26.2	72.6	L1.5*	7.62	98.7	O3 *	7.86	61.7	R2 *	7.44
1989-1993	33.9	82.6	L1	8.54	71.9	S0.5	7.99	144.6	SC *	8.21
1990-1994	43.3	70.9	L1.5*	5.06	64.3	S1	4.59	133.5	SC *	5.07
1991-1995	55.2	63.4	L1.5*	3.46	61.7	L1.5 *	3.57	130.0	SC *	2.92
1992-1996	45.4	57.9	L1.5*	4.48	54.3	S1.5	5.08	109.1	O3 *	3.98
1993-1997	36.1	51.8	L2*	3.79	49.9	S1.5	4.30	79.7	O3 *	2.99
1994-1998	26.1	49.1	L2*	3.99	48.3	S2	4.68	51.1	L3 *	4.09
1995-1999	0.0	43.2	L2*	5.25	43.0	R2.5	3.97	43.2	R2.5	4.26
1996-2000	0.0	43.0	L2*	5.86	41.3	R1.5	2.17	41.7	R2	2.49
1997-2001	0.0	42.2	L2*	6.32	38.8	R1	4.24	40.2	R1.5	2.25
1998-2002	5.7	44.0	L2*	6.12	38.5	R0.5	4.99	40.1	R1	2.38
1999-2003	12.0	44.5	L1.5*	5.76	38.0	R0.5	7.15	38.6	R0.5	6.02
2000-2004	26.0	53.0	L1	4.52	43.6	R0.5	6.12	43.5	SC	6.41
2001-2005	29.8	58.5	L0.5	4.95	48.0	R0.5	4.38	48.2	R0.5	4.91
2002-2006	55.2	77.8	L0	2.31	63.5	R0.5	2.71	101.2	O3 *	3.15
2003-2007	57.2	76.9	L0.5	2.07	83.1	L0	2.05	124.7	SC *	1.95
2004-2008	0.0	73.3	L1.5*	6.18	67.9	S0.5	6.11	64.8	R1.5 *	5.91
2005-2009	29.0	67.0	L1.5*	2.90	58.9	R1.5	3.21	57.6	R2 *	2.11
2006-2010	21.3	59.7	L1*	3.59	54.2	R1	5.14	53.0	R1 *	3.88
2007-2011	15.2	49.4	L0.5	4.95	44.6	SC	7.80	45.1	S-.5 *	4.96
2008-2012	16.8	48.4	L0	5.23	43.2	SC	8.37	44.4	S-.5 *	4.69
2009-2013	15.0	44.3	O2	5.81	39.2	O2	8.21	41.1	SC *	3.46

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

T-Cut: None
Placement Band: 1936-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-2013	19.3	57.2	L1.5*	3.71	52.5	R1.5	1.24	52.3	R1.5	1.36
1983-2013	19.0	56.7	L1.5*	3.70	52.1	R1.5	1.21	51.8	R1.5	1.37
1985-2013	18.7	56.0	L1.5*	3.71	51.5	S0.5	1.18	51.2	R1.5	1.35
1987-2013	18.2	55.1	L1.5*	3.61	50.7	R1	1.15	50.5	R1.5	1.30
1989-2013	17.9	54.4	L1.5*	3.39	50.3	R1	1.18	50.0	R1	1.24
1991-2013	17.3	53.2	L1.5*	3.16	49.5	S0	1.18	49.2	R1	1.23
1993-2013	17.0	52.7	L1.5*	3.26	49.1	S0	1.31	48.8	R1	1.35
1995-2013	16.3	51.6	L1*	3.25	48.0	S0	1.44	47.9	R1	1.45
1997-2013	16.4	51.2	L1	2.85	46.9	R0.5	2.44	47.1	R1	1.48
1999-2013	17.1	51.4	L0.5	2.73	46.3	R0.5	3.42	46.8	R0.5	1.56
2001-2013	20.2	54.8	L0.5	3.04	48.6	SC	3.76	49.0	R0.5 *	1.34
2003-2013	22.7	56.7	L0	3.41	51.1	SC	4.59	50.4	R1 *	1.74
2005-2013	22.2	54.9	L0	4.53	49.8	SC	6.13	49.0	R0.5 *	3.07
2007-2013	17.9	49.5	L0	5.22	45.4	SC	7.15	45.5	S-.5 *	4.05
2009-2013	15.0	44.3	O2	5.81	39.2	O2	8.21	41.1	SC *	3.46
2011-2013	14.5	41.5	O3	7.80	37.1	O3	9.53	39.3	L0 *	4.64
2013-2013	0.0	43.1	O3	48.31	33.9	O3	44.63	37.6	L0 *	53.78

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

T-Cut: None

Placement Band: 1936-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Dispersion	First Degree Conf. Index	Second Degree Average Life	Second Degree Dispersion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Dispersion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-1982	99.0	195.3	SQ*	0.77	195.3	SQ*	0.72	77.3	R4*	0.64
1981-1984	78.3	159.3	R1.5*	5.06	107.1	S2	4.86	68.2	R4*	4.41
1981-1986	96.1	173.8	R2.5*	0.56	130.7	S1.5	0.47	78.6	R4*	0.43
1981-1988	88.5	124.1	S0*	1.36	79.6	S2	1.03	68.9	R3	1.29
1981-1990	60.2	125.3	S0*	5.44	83.5	S2	4.82	68.7	S3	4.48
1981-1992	29.6	92.8	L1.5*	9.66	77.2	S1	9.14	66.7	R3*	8.72
1981-1994	49.4	86.5	L1.5*	6.29	69.0	S1.5	5.08	71.3	S1.5	5.15
1981-1996	57.6	71.7	L1.5*	2.85	61.0	S1.5	2.47	62.6	S1.5	2.32
1981-1998	38.5	62.4	L2*	4.12	54.6	S2	1.81	53.6	R3	2.47
1981-2000	0.0	55.9	L2*	6.85	50.0	R2.5	3.28	49.9	R3*	3.15
1981-2002	8.9	54.8	L2*	6.18	48.9	R2	2.33	49.1	R2.5	2.16
1981-2004	21.6	55.9	L2*	5.34	49.9	R2	1.51	49.9	R2.5	1.54
1981-2006	30.1	58.4	L2*	4.15	52.2	R2	1.78	52.0	R2	1.86
1981-2008	0.0	58.5	L2*	5.15	52.9	R2	3.20	53.0	R2	3.20
1981-2010	16.3	58.2	L1.5*	3.72	52.9	R1.5	1.81	52.7	R2	1.93
1981-2012	19.6	57.4	L1.5*	3.64	52.6	R1.5	1.30	52.3	R1.5	1.46
1981-2013	19.3	57.2	L1.5*	3.71	52.5	R1.5	1.24	52.3	R1.5	1.36

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

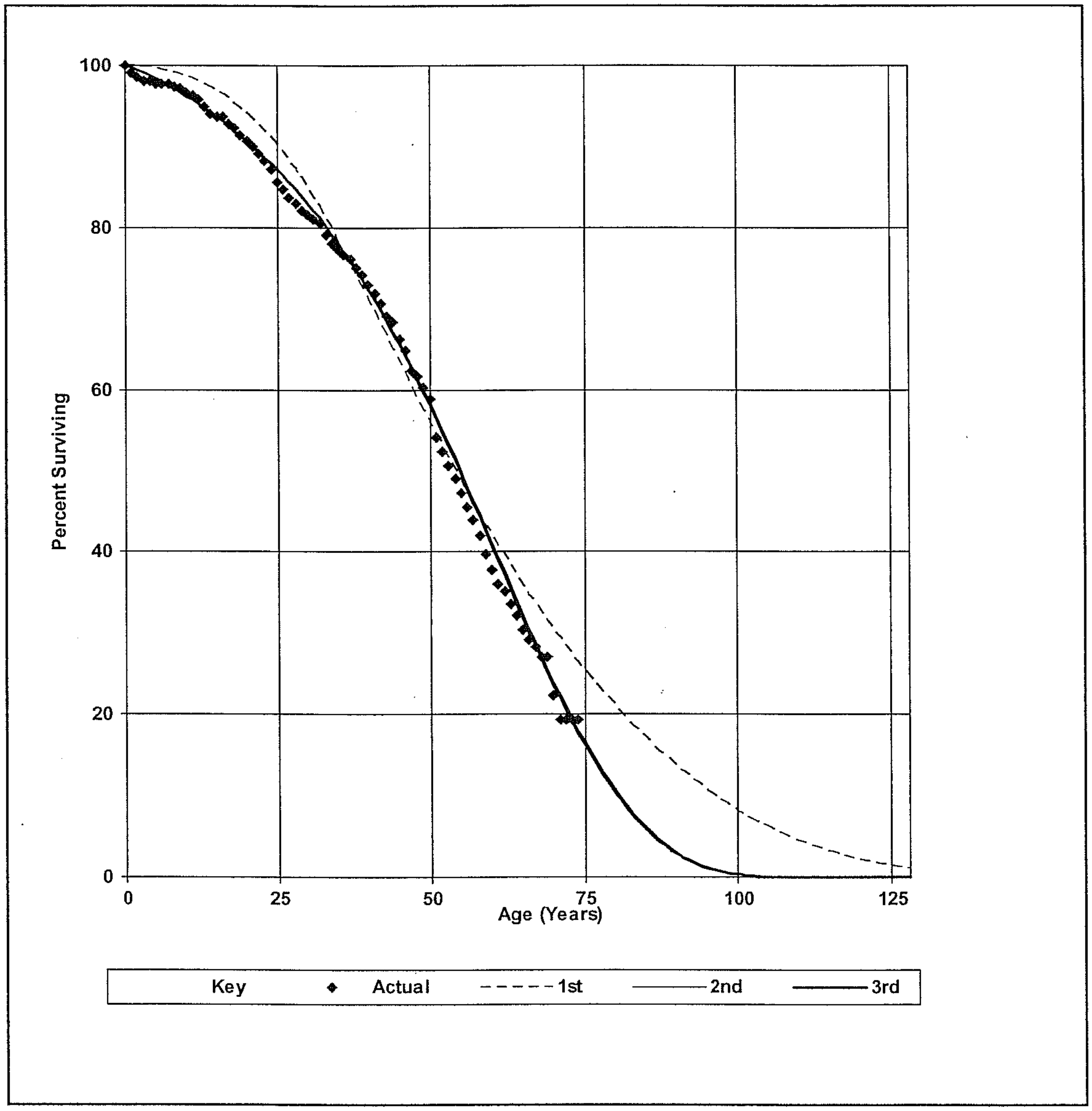
T-Cut: None

Placement Band: 1936-2013 Observation Band: 1981-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 57.2-L1.5 2nd: 52.5-R1.5 3rd: 52.3-R1.5



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

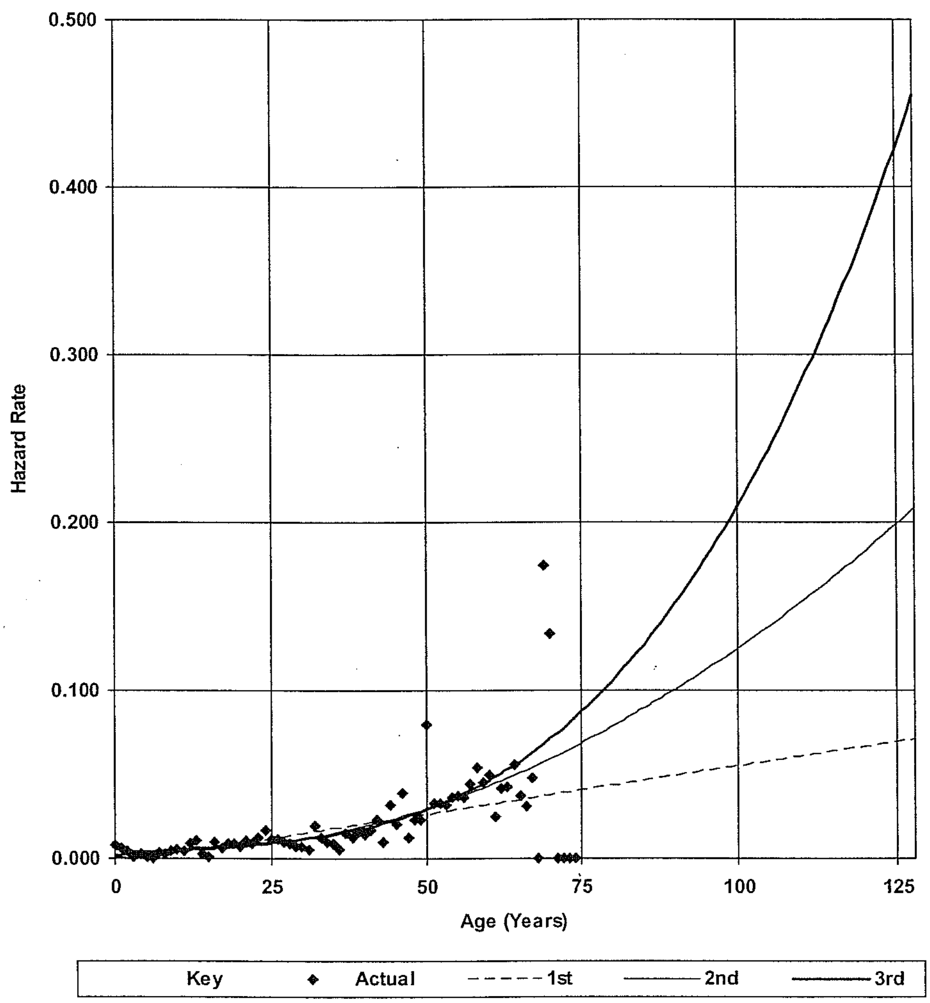
T-Cut: None

Placement Band: 1936-2013 Observation Band: 1981-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function 1st: 57.2-L1.5 2nd: 52.5-R1.5 3rd: 52.3-R1.5



Schedule E

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050BRKX 50kV Breakers

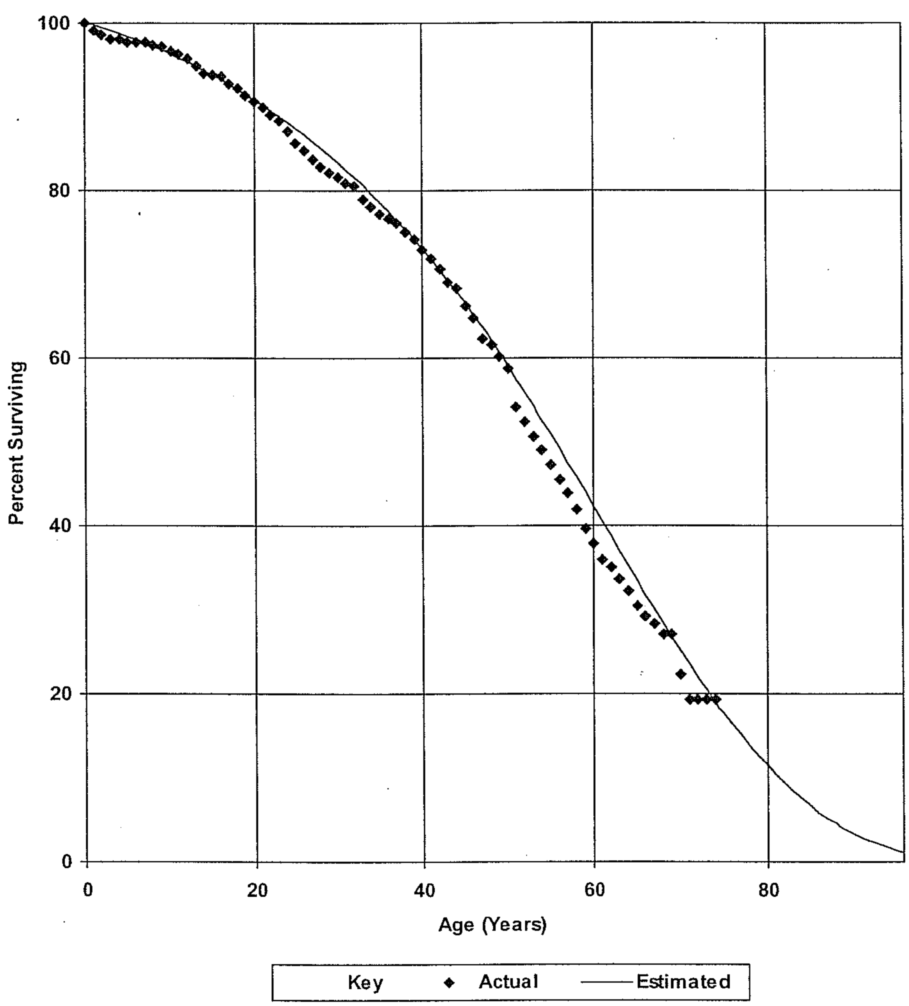
T-Cut: None

Placement Band: 1936-2013

Observation Band: 1981-2013

Estimated Projection Life Curve

53.0-R1.5



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONA 50kV Conventional and Metalclad Air Breakers

Placement Band: 1949 - 1987
Observation Band: 1983 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	27	0	0.00000	1.00000	1.00000
0.5	45	0	0.00000	1.00000	1.00000
1.5	77	0	0.00000	1.00000	1.00000
2.5	116	0	0.00000	1.00000	1.00000
3.5	122	0	0.00000	1.00000	1.00000
4.5	125	0	0.00000	1.00000	1.00000
5.5	144	0	0.00000	1.00000	1.00000
6.5	150	0	0.00000	1.00000	1.00000
7.5	168	0	0.00000	1.00000	1.00000
8.5	179	0	0.00000	1.00000	1.00000
9.5	181	0	0.00000	1.00000	1.00000
10.5	217	0	0.00000	1.00000	1.00000
11.5	224	0	0.00000	1.00000	1.00000
12.5	249	0	0.00000	1.00000	1.00000
13.5	284	0	0.00000	1.00000	1.00000
14.5	297	0	0.00000	1.00000	1.00000
15.5	349	4	0.01146	0.98854	1.00000
16.5	348	0	0.00000	1.00000	0.98854
17.5	350	0	0.00000	1.00000	0.98854
18.5	352	1	0.00284	0.99716	0.98854
19.5	351	4	0.01140	0.98860	0.98573
20.5	356	2	0.00562	0.99438	0.97450
21.5	355	0	0.00000	1.00000	0.96902
22.5	355	4	0.01127	0.98873	0.96902
23.5	352	4	0.01136	0.98864	0.95810
24.5	365	0	0.00000	1.00000	0.94722
25.5	368	10	0.02717	0.97283	0.94722
26.5	373	3	0.00804	0.99196	0.92148
27.5	370	7	0.01892	0.98108	0.91407
28.5	365	2	0.00548	0.99452	0.89677
29.5	363	8	0.02204	0.97796	0.89186
30.5	345	0	0.00000	1.00000	0.87220
31.5	326	30	0.09202	0.90798	0.87220
32.5	272	10	0.03676	0.96324	0.79194
33.5	236	3	0.01271	0.98729	0.76282
34.5	229	8	0.03493	0.96507	0.75313
35.5	219	2	0.00913	0.99087	0.72682

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONA 50kV Conventional and Metalclad Air Breakers

Placement Band: 1949 - 1987
Observation Band: 1983 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	202	12	0.05941	0.94059	0.72018
37.5	185	1	0.00541	0.99459	0.67740
38.5	190	1	0.00526	0.99474	0.67373
39.5	178	15	0.08427	0.91573	0.67019
40.5	163	0	0.00000	1.00000	0.61371
41.5	128	2	0.01563	0.98438	0.61371
42.5	120	0	0.00000	1.00000	0.60412
43.5	101	4	0.03960	0.96040	0.60412
44.5	70	1	0.01429	0.98571	0.58020
45.5	60	0	0.00000	1.00000	0.57191
46.5	53	0	0.00000	1.00000	0.57191
47.5	53	0	0.00000	1.00000	0.57191
48.5	53	0	0.00000	1.00000	0.57191
49.5	51	15	0.29412	0.70588	0.57191
50.5	28	0	0.00000	1.00000	0.40370
51.5	28	0	0.00000	1.00000	0.40370
52.5	23	1	0.04348	0.95652	0.40370
53.5	22	0	0.00000	1.00000	0.38615
54.5	22	3	0.13636	0.86364	0.38615
55.5	19	0	0.00000	1.00000	0.33349
56.5	16	4	0.25000	0.75000	0.33349
57.5	10	1	0.10000	0.90000	0.25012
58.5	9	0	0.00000	1.00000	0.22511
59.5	1	1	1.00000	0.00000	0.22511
60.5	0	0	0.00000	1.00000	0.00000

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONA 50kV Conventional and Metalclad Air Breakers

T-Cut: None

Placement Band: 1949-1987

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1983-1987	92.3	77.8	L1.5*	1.98	48.6	S2*	2.20	46.2	S3*	2.01
1984-1988	96.9	120.9	S-.5	2.86	187.0	R4*	2.26	85.1	R4*	2.19
1985-1989	96.6	146.0	R1	2.37	187.6	R4*	1.84	67.1	R4*	1.71
1986-1990	95.7	171.6	R2	1.84	188.2	R5*	1.21	64.2	R4*	1.06
1987-1991	59.5	49.8	L2*	4.36	47.1	S1.5*	4.32	121.5	SC*	4.96
1988-1992	65.4	52.2	L2*	3.15	63.0	L0.5*	3.19	128.7	SC*	5.12
1989-1993	69.8	55.5	L2*	3.88	64.1	L1.5*	3.98	127.0	SC*	10.60
1990-1994	52.0	46.6	L2*	5.22	76.3	O4*	5.24	90.6	O4*	18.45
1991-1995	39.9	42.0	L2*	7.48	76.0	O4*	7.65	62.8	O4*	27.89
1992-1996	33.8	42.6	L3*	7.98	55.9	O3*	7.98	51.2	O4*	35.62
1993-1997	28.7	43.6	L3*	11.05	68.2	O4*	10.63	40.6	O4*	43.63
1994-1998	23.9	44.7	L3*	14.41	84.2	O4*	13.42	36.6	O4*	46.22
1995-1999	0.0	35.4	S3*	8.16	36.0	S3*	9.36	35.9	S3*	10.18
1996-2000	0.0	36.6	S3*	6.54	32.2	R1.5	12.86	37.1	R3*	8.01
1997-2001	0.0	38.9	S3*	12.91	25.3	SC	33.70	39.0	R3*	10.83
1998-2002	0.0	38.7	S3*	13.46	21.0	O3	42.28	38.6	R3*	10.82
1999-2003	5.3	39.1	S3*	11.88	17.3	O4	49.19	38.6	R3*	9.47
2000-2004	76.7	103.0	L0	4.97	64.5	R1	11.13	62.6	R1.5	7.10
2001-2005	74.1	97.0	L1*	4.04	148.9	SC*	4.36	76.3	R2.5*	4.56
2002-2006	63.1	93.0	L1*	7.89	145.1	SC*	8.49	124.3	SC*	19.90
2003-2007	54.7	58.3	L2*	6.08	134.5	SC*	5.76	71.1	O4*	37.22
2004-2008	46.1	54.4	L2*	7.38	124.1	SC*	6.75	39.6	O4*	53.97
2005-2009	53.4	46.5	O2	17.25	120.6	SC*	2.43	119.9	SC*	2.46
2006-2010	54.1	43.8	O2	20.11	114.8	O3*	2.93	113.5	O3*	3.23
2007-2011	17.6	48.0	S1.5*	5.92	47.7	S1.5*	6.12	47.7	S2*	3.43
2008-2012	42.8	57.5	L3*	4.63	25.6	O4	47.87	53.3	R4*	2.87
2009-2013	0.0	58.0	S3*	7.99	6.5	O4	79.45	54.3	R4*	4.59

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONA 50kV Conventional and Metalclad Air Breakers

T-Cut: None

Placement Band: 1949-1987

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1983-2013	0.0	48.8	L2*	4.82	47.5	S2*	4.24	46.9	S2*	4.24
1985-2013	0.0	48.9	L2*	4.68	47.5	S2*	4.22	46.8	S2*	4.20
1987-2013	0.0	48.7	L2*	4.52	47.4	S1.5*	4.19	46.5	S1.5*	4.15
1989-2013	0.0	48.6	S1.5*	4.56	47.6	S2*	4.34	46.6	S2*	4.33
1991-2013	0.0	48.0	L3*	4.33	47.2	S1.5*	4.23	46.0	S1.5*	4.17
1993-2013	0.0	48.7	L3*	4.40	47.7	S2*	4.29	46.5	S2*	4.10
1995-2013	0.0	48.8	L3*	4.19	47.5	S2*	4.12	46.6	S2*	3.74
1997-2013	0.0	50.5	L3*	4.80	42.5	R1	11.83	47.6	R3*	3.85
1999-2013	0.0	49.4	L3*	4.72	37.2	SC	18.98	46.8	R2.5*	3.77
2001-2013	0.0	58.4	L3*	6.79	43.4	R0.5	19.75	52.6	R3*	5.52
2003-2013	0.0	58.1	L3*	7.06	39.1	SC	26.39	52.4	R3*	5.46
2005-2013	0.0	55.9	L3*	6.87	32.2	O2	35.16	51.5	R3*	5.06
2007-2013	0.0	53.2	L3*	7.04	22.7	O4	48.37	50.3	R3*	4.81
2009-2013	0.0	58.0	S3*	7.99	6.5	O4	79.45	54.3	R4*	4.59
2011-2013	0.0	54.9	L4*	16.94	2.7	O4*	86.65	55.5	S5*	16.64
2013-2013	0.0	56.9	S4*	16.55	1.8	O3*	94.29	57.0	S6*	9.61

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONA 50kV Conventional and Metalclad Air Breakers

T-Cut: None

Placement Band: 1949-1987

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1983-1984	84.6	48.4	L2*	6.38	35.1	S3*	7.03	32.9	S4*	5.22
1983-1986	92.0	68.5	L1.5*	2.78	44.3	S3*	3.29	41.0	R4*	2.61
1983-1988	90.4	77.2	L1.5*	2.63	157.5	R0.5*	2.48	175.1	R2*	2.38
1983-1990	93.2	105.1	L1*	1.43	183.3	R4*	1.22	184.1	R4*	1.20
1983-1992	66.3	55.5	L2*	3.54	50.9	S1.5*	3.40	136.2	SC*	3.07
1983-1994	61.6	53.0	L2*	4.12	50.7	S1*	4.12	129.4	SC*	3.39
1983-1996	42.7	45.6	L2*	6.71	43.9	S1.5*	6.40	99.6	O4*	6.30
1983-1998	46.0	49.8	L2*	7.66	48.7	S1*	7.61	111.6	O3*	6.18
1983-2000	0.0	40.0	L3*	6.92	39.2	S3*	6.99	39.5	R3*	7.39
1983-2002	0.0	41.9	L3*	6.48	40.7	S3*	6.31	40.7	R3*	6.49
1983-2004	22.2	44.5	S1.5*	5.26	42.9	S2*	5.27	42.7	R3*	5.34
1983-2006	30.8	47.0	L2*	4.54	45.2	S2*	4.49	45.0	S2*	4.51
1983-2008	28.9	46.0	L2*	3.69	44.9	S2*	3.34	60.3	O3*	3.30
1983-2010	31.0	47.3	L2*	3.55	46.5	S1.5*	3.39	80.9	O4*	3.39
1983-2012	22.2	48.2	L2*	3.52	47.0	S1.5*	3.09	47.5	S1.5*	3.05
1983-2013	0.0	48.8	L2*	4.82	47.5	S2*	4.24	46.9	S2*	4.24

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONA 50kV Conventional and Metalclad Air Breakers

T-Cut: None

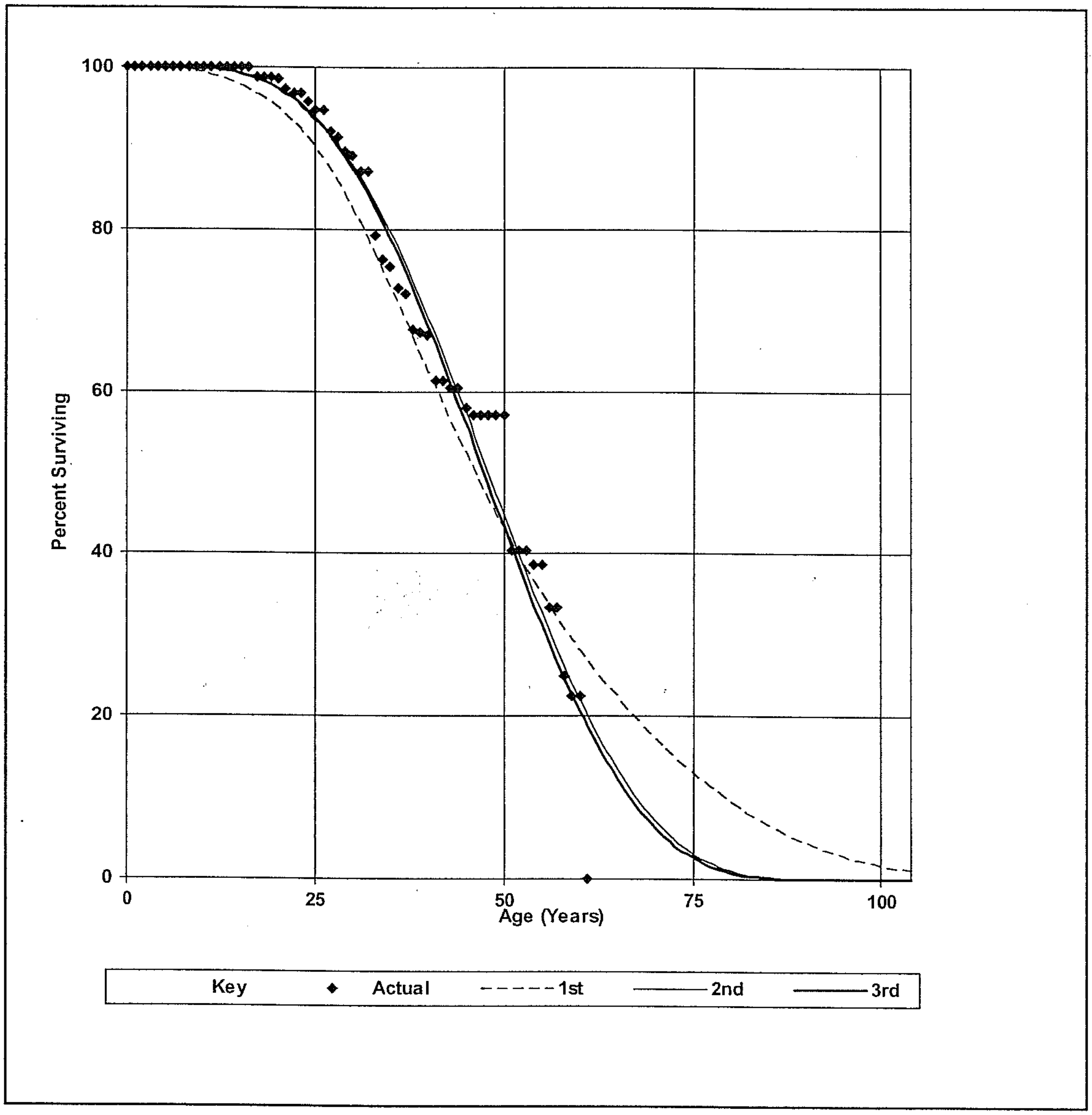
Placement Band: 1949-1987 Observation Band: 1983-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 48.8-L2 2nd: 47.5-S2 3rd: 46.9-S2



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONA 50kV Conventional and Metalclad Air Breakers

T-Cut: None

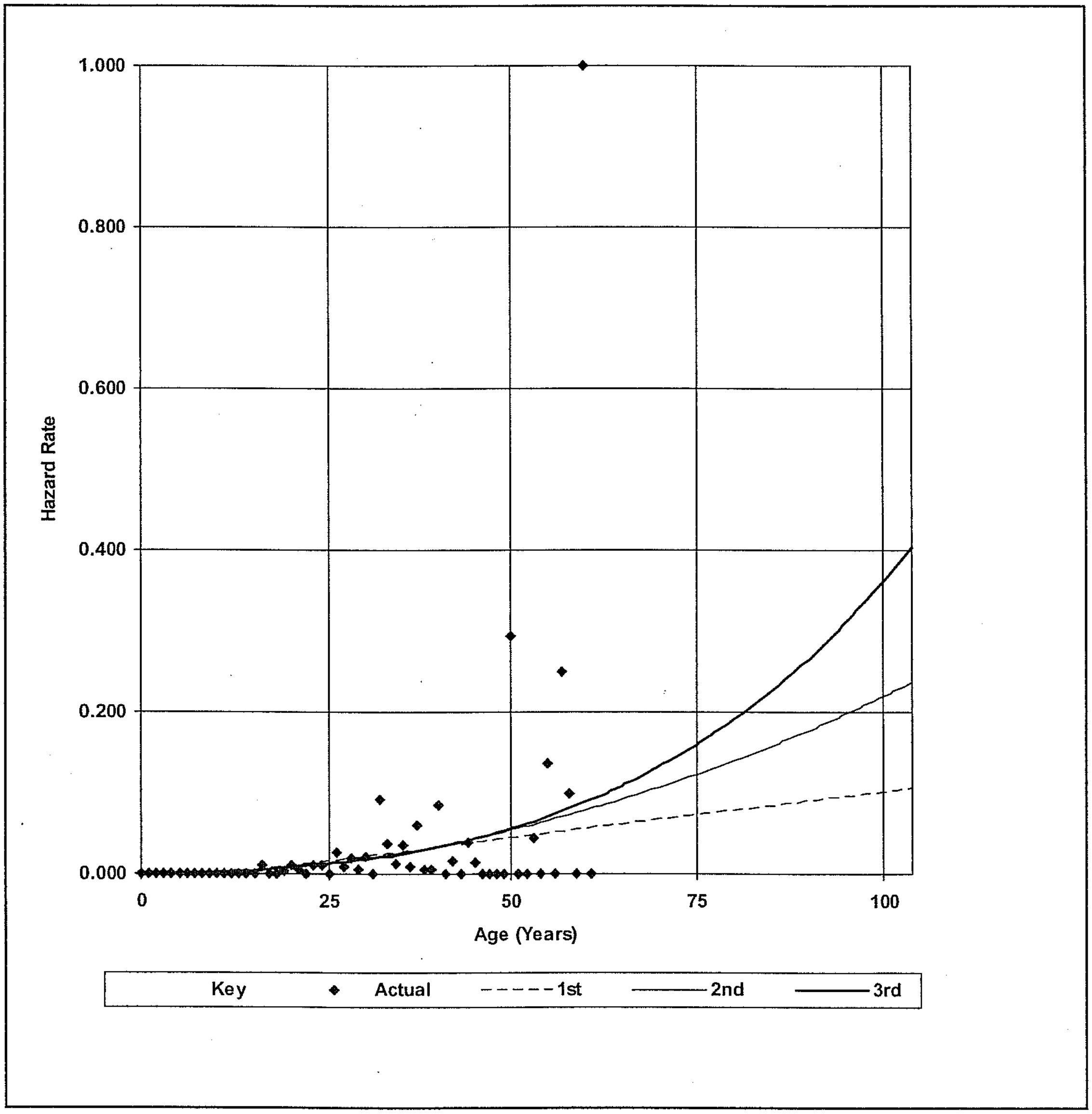
Placement Band: 1949-1987 Observation Band: 1983-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 48.8-L2 2nd: 47.5-S2 3rd: 46.9-S2



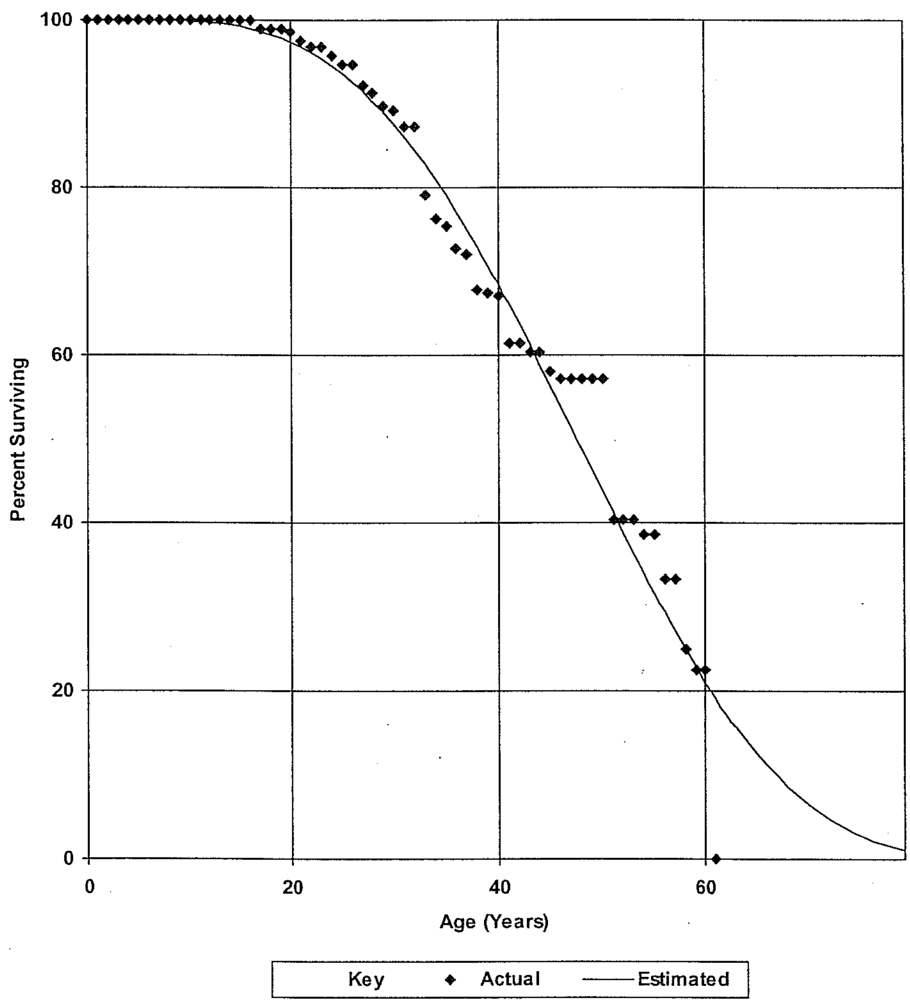
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONA 50kV Conventional and Metalclad Air Breakers

T-Cut: None
Placement Band: 1949-1987
Observation Band: 1983-2013

Estimated Projection Life Curve 47.0-S2



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

Placement Band: 1936 - 2011
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	121	4	0.03306	0.96694	1.00000
0.5	126	0	0.00000	1.00000	0.96694
1.5	208	1	0.00481	0.99519	0.96694
2.5	228	0	0.00000	1.00000	0.96229
3.5	235	0	0.00000	1.00000	0.96229
4.5	298	0	0.00000	1.00000	0.96229
5.5	369	0	0.00000	1.00000	0.96229
6.5	461	1	0.00217	0.99783	0.96229
7.5	530	2	0.00377	0.99623	0.96021
8.5	597	1	0.00168	0.99832	0.95658
9.5	661	3	0.00454	0.99546	0.95498
10.5	743	0	0.00000	1.00000	0.95065
11.5	854	2	0.00234	0.99766	0.95065
12.5	902	1	0.00111	0.99889	0.94842
13.5	1,022	2	0.00196	0.99804	0.94737
14.5	1,074	0	0.00000	1.00000	0.94551
15.5	1,119	3	0.00268	0.99732	0.94551
16.5	1,184	3	0.00253	0.99747	0.94298
17.5	1,198	9	0.00751	0.99249	0.94059
18.5	1,235	6	0.00486	0.99514	0.93352
19.5	1,263	2	0.00158	0.99842	0.92899
20.5	1,272	1	0.00079	0.99921	0.92752
21.5	1,310	4	0.00305	0.99695	0.92679
22.5	1,313	3	0.00228	0.99772	0.92396
23.5	1,345	11	0.00818	0.99182	0.92185
24.5	1,369	11	0.00804	0.99196	0.91431
25.5	1,370	7	0.00511	0.99489	0.90696
26.5	1,372	6	0.00437	0.99563	0.90233
27.5	1,426	9	0.00631	0.99369	0.89838
28.5	1,484	7	0.00472	0.99528	0.89271
29.5	1,516	6	0.00396	0.99604	0.88850
30.5	1,525	7	0.00459	0.99541	0.88498
31.5	1,511	5	0.00331	0.99669	0.88092
32.5	1,563	13	0.00832	0.99168	0.87801
33.5	1,603	15	0.00936	0.99064	0.87070
34.5	1,547	8	0.00517	0.99483	0.86256
35.5	1,526	7	0.00459	0.99541	0.85810

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

Placement Band: 1936 - 2011
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	1,518	14	0.00922	0.99078	0.85416
37.5	1,454	19	0.01307	0.98693	0.84628
38.5	1,372	24	0.01749	0.98251	0.83522
39.5	1,273	6	0.00471	0.99529	0.82061
40.5	1,232	23	0.01867	0.98133	0.81674
41.5	1,146	27	0.02356	0.97644	0.80150
42.5	1,071	12	0.01120	0.98880	0.78261
43.5	988	31	0.03138	0.96862	0.77385
44.5	877	18	0.02052	0.97948	0.74956
45.5	822	34	0.04136	0.95864	0.73418
46.5	697	9	0.01291	0.98709	0.70381
47.5	649	16	0.02465	0.97535	0.69472
48.5	599	15	0.02504	0.97496	0.67760
49.5	537	32	0.05959	0.94041	0.66063
50.5	489	17	0.03476	0.96524	0.62126
51.5	432	15	0.03472	0.96528	0.59966
52.5	388	12	0.03093	0.96907	0.57884
53.5	364	14	0.03846	0.96154	0.56094
54.5	329	10	0.03040	0.96960	0.53937
55.5	313	12	0.03834	0.96166	0.52297
56.5	275	9	0.03273	0.96727	0.50292
57.5	247	13	0.05263	0.94737	0.48646
58.5	232	11	0.04741	0.95259	0.46086
59.5	220	10	0.04545	0.95455	0.43901
60.5	198	5	0.02525	0.97475	0.41905
61.5	166	7	0.04217	0.95783	0.40847
62.5	141	6	0.04255	0.95745	0.39125
63.5	124	7	0.05645	0.94355	0.37460
64.5	107	4	0.03738	0.96262	0.35345
65.5	64	2	0.03125	0.96875	0.34024
66.5	41	2	0.04878	0.95122	0.32961
67.5	27	0	0.00000	1.00000	0.31353
68.5	22	4	0.18182	0.81818	0.31353
69.5	14	2	0.14286	0.85714	0.25652
70.5	10	0	0.00000	1.00000	0.21988
71.5	7	0	0.00000	1.00000	0.21988
72.5	4	0	0.00000	1.00000	0.21988

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

Placement Band: 1936 - 2011
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	0	0	0.00000	1.00000	0.21988

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1936-2011
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-1985	96.3	183.3	R4	0.74	107.7	S2 *	0.64	69.0	S4 *	0.76
1982-1986	97.4	178.0	R3 *	0.59	107.4	S2 *	0.55	74.8	S4 *	0.57
1983-1987	97.6	179.2	R3 *	0.54	112.2	S2 *	0.50	78.6	S4 *	0.45
1984-1988	90.2	108.1	L1.5 *	1.54	79.9	S2	1.67	71.0	S3 *	1.68
1985-1989	91.7	105.3	L1.5 *	2.33	82.3	S1.5	2.70	74.0	R3 *	2.60
1986-1990	60.7	102.0	L1.5 *	4.78	81.1	S1.5	4.68	65.8	R3 *	4.27
1987-1991	29.2	92.5	L1.5 *	7.79	83.0	S1	7.68	61.4	R3 *	6.84
1988-1992	27.4	76.1	L1.5 *	8.02	74.4	L1.5 *	7.98	58.6	R3 *	7.10
1989-1993	37.4	84.2	L1.5 *	7.98	87.3	L1.5 *	8.02	62.0	R3 *	7.20
1990-1994	48.9	73.9	L2 *	4.83	67.7	S1.5 *	4.50	61.7	R3 *	4.09
1991-1995	61.0	67.8	L2 *	5.64	66.5	L2 *	5.68	122.9	SC *	5.40
1992-1996	48.2	60.3	S1.5 *	9.71	57.9	S2 *	10.14	100.3	O3 *	6.63
1993-1997	37.0	53.7	L3 *	9.85	52.5	S2 *	10.58	71.3	O3 *	5.25
1994-1998	24.7	50.9	L3 *	14.07	49.6	S2 *	13.83	48.3	R2.5 *	11.18
1995-1999	0.0	48.0	L3 *	17.10	44.5	R2	12.47	47.2	R3 *	17.08
1996-2000	0.0	48.0	L3 *	29.32	42.4	R1.5	21.15	43.4	R2	22.85
1997-2001	0.0	47.1	L3 *	11.03	38.4	R1	4.86	41.1	R1.5	3.00
1998-2002	6.6	50.3	L3 *	9.22	40.4	R1	6.81	43.4	R1.5	2.71
1999-2003	13.7	51.6	L3 *	11.64	43.6	R1.5	3.35	38.5	SC *	10.02
2000-2004	23.2	56.8	L3 *	16.75	44.9	R0.5	4.13	50.7	O4 *	19.14
2001-2005	29.6	61.6	L3 *	12.64	53.8	R1.5	5.80	65.8	O4 *	20.58
2002-2006	55.9	77.1	L1.5 *	8.51	68.7	S0.5	4.90	90.2	O4 *	21.69
2003-2007	55.4	82.5	L1 *	8.73	69.8	R1	4.05	87.2	O4 *	23.49
2004-2008	0.0	78.2	L2 *	23.10	51.7	SC	7.18	53.9	O2 *	9.06
2005-2009	16.6	70.8	L3 *	34.69	40.8	SC	12.24	43.1	SC	12.08
2006-2010	13.8	66.5	L3 *	28.31	37.4	O3	13.09	39.2	SC	11.21
2007-2011	13.4	62.8	L3 *	26.62	28.6	O4	22.31	26.6	O4	25.25
2008-2012	7.8	62.7	L3 *	49.26	24.5	O4	11.90	15.8	O4 *	21.40
2009-2013	0.0	64.0	L2 *	79.31	11.4	O4	18.16	5.1	O4 *	9.63

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1936-2011
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-2013	22.0	61.8	L2*	4.71	56.9	R2.5	2.06	56.8	R2.5	1.62
1983-2013	20.6	61.4	L2*	8.37	56.4	R2.5	5.66	56.0	R2	4.65
1985-2013	19.7	61.0	L2*	10.68	55.4	R2	7.04	54.6	R1.5 *	5.09
1987-2013	19.0	60.4	S1.5*	11.74	54.2	R2	6.95	53.0	R1.5 *	3.70
1989-2013	18.5	60.1	S1.5*	13.02	53.2	R1.5	6.96	52.1	R1 *	2.46
1991-2013	16.7	59.5	S1.5*	17.47	52.4	R1.5	10.65	52.5	R0.5 *	4.15
1993-2013	15.0	59.4	L3*	22.80	52.0	R1.5	15.36	53.8	O2 *	6.29
1995-2013	12.8	58.8	L3*	29.02	49.5	R1	18.78	50.7	O2 *	8.73
1997-2013	14.4	59.2	L3*	23.15	46.0	R0.5	7.85	45.6	O3 *	5.85
1999-2013	12.0	61.9	L3*	36.63	43.4	SC	14.93	41.3	O3 *	3.28
2001-2013	10.6	64.7	L3*	44.88	40.2	SC	16.77	37.3	O4 *	5.94
2003-2013	10.0	67.9	L2*	49.12	33.5	O3	10.62	29.1	O4 *	5.04
2005-2013	0.0	68.4	L3*	82.84	30.3	O4	40.38	24.6	O4 *	32.21
2007-2013	0.0	65.2	L3*	81.30	20.8	O4	29.22	13.1	O4 *	17.48
2009-2013	0.0	64.0	L2*	79.31	11.4	O4	18.16	5.1	O4 *	9.63
2011-2013	0.0	65.3	L2*	79.54	8.9	O4	15.32	2.7	O4 *	7.97
2013-2013	0.0	55.5	O4*	51.09	2.0	O3 *	7.89	0.7	O2 *	11.97

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1936-2011
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-1982	99.0	195.3	SQ*	0.77	195.3	SQ*	0.72	77.3	R4*	0.64
1981-1984	79.5	178.3	R3	5.19	99.1	S2*	4.85	64.7	S4*	4.03
1981-1986	97.1	186.8	R4	0.60	115.8	S2*	0.52	73.2	S4*	0.60
1981-1988	90.7	120.7	S0.5*	1.18	80.2	S2	1.34	66.1	R4*	1.63
1981-1990	61.3	121.2	S0*	5.29	84.2	S2	4.85	66.5	R4*	4.26
1981-1992	30.7	97.6	L1.5*	10.00	77.0	S1.5	9.35	63.0	R4*	8.23
1981-1994	52.3	89.0	L1.5*	6.33	70.5	S2	5.23	63.4	R3*	4.43
1981-1996	61.0	74.9	L2*	3.17	62.5	S2	2.31	59.7	R3*	3.39
1981-1998	39.7	62.9	L2*	4.32	54.9	R2.5	1.78	54.2	R3*	3.29
1981-2000	0.0	58.7	L2*	7.30	51.8	R2.5*	3.71	52.4	R4*	3.60
1981-2002	9.9	57.2	S1.5*	6.27	51.1	R2.5*	2.74	52.3	R3*	3.05
1981-2004	23.6	58.0	L2*	5.28	52.6	R2.5	1.65	53.2	R3	2.53
1981-2006	32.7	60.5	L2*	4.24	55.5	R2.5	2.46	55.5	R2.5	2.18
1981-2008	0.0	61.1	L2*	5.57	56.3	S2	3.93	56.3	S2	3.68
1981-2010	16.4	61.2	L2*	4.30	56.4	R2.5	2.66	56.3	R2.5	2.48
1981-2012	21.8	61.4	L2*	4.30	56.9	R2.5	2.21	56.7	R2.5	1.74
1981-2013	22.0	61.8	L2*	4.71	56.9	R2.5	2.06	56.8	R2.5	1.62

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

T-Cut: None

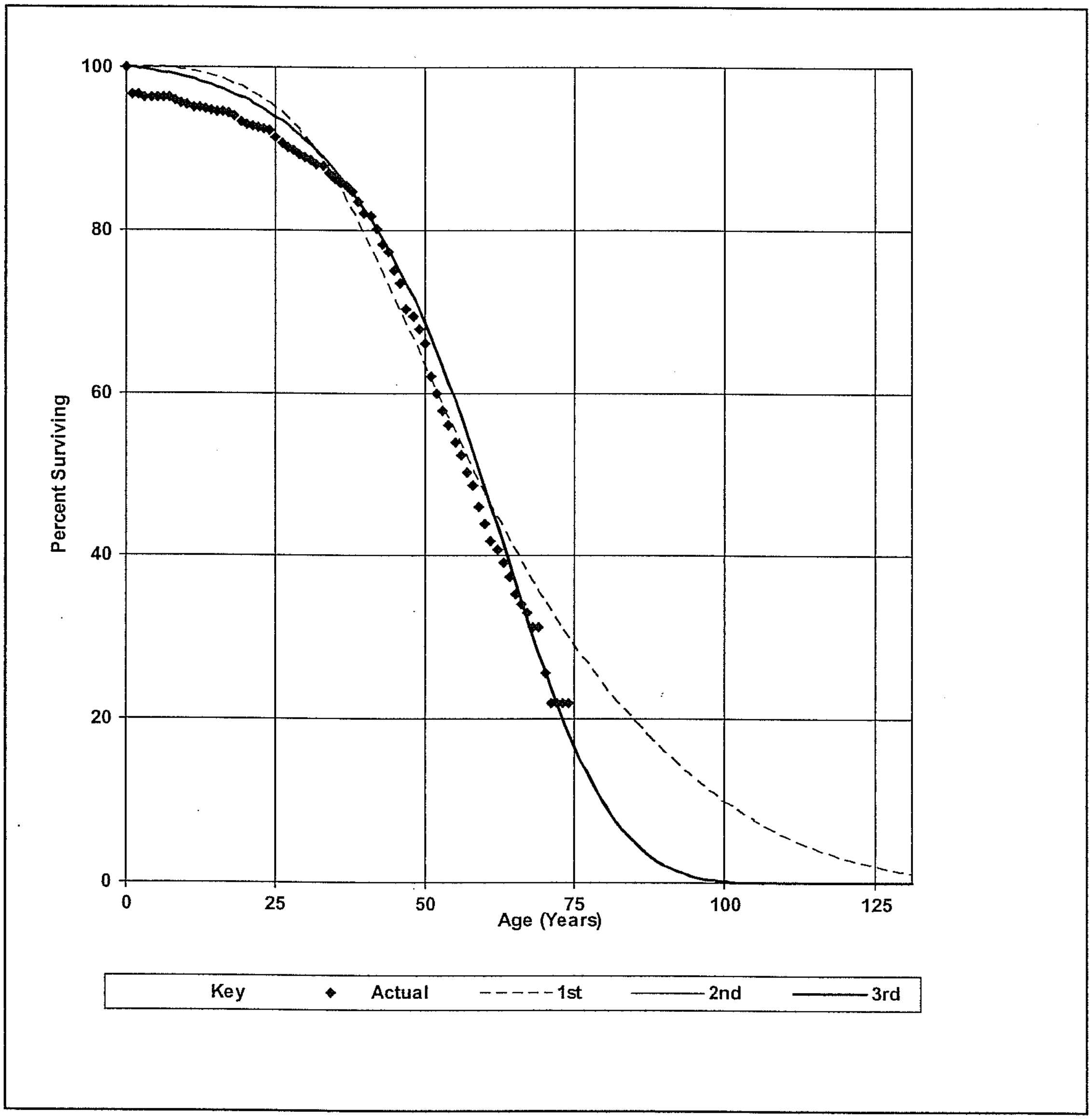
Placement Band: 1936-2011 Observation Band: 1981-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 61.8-L2 2nd: 56.9-R2.5 3rd: 56.8-R2.5



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

T-Cut: None

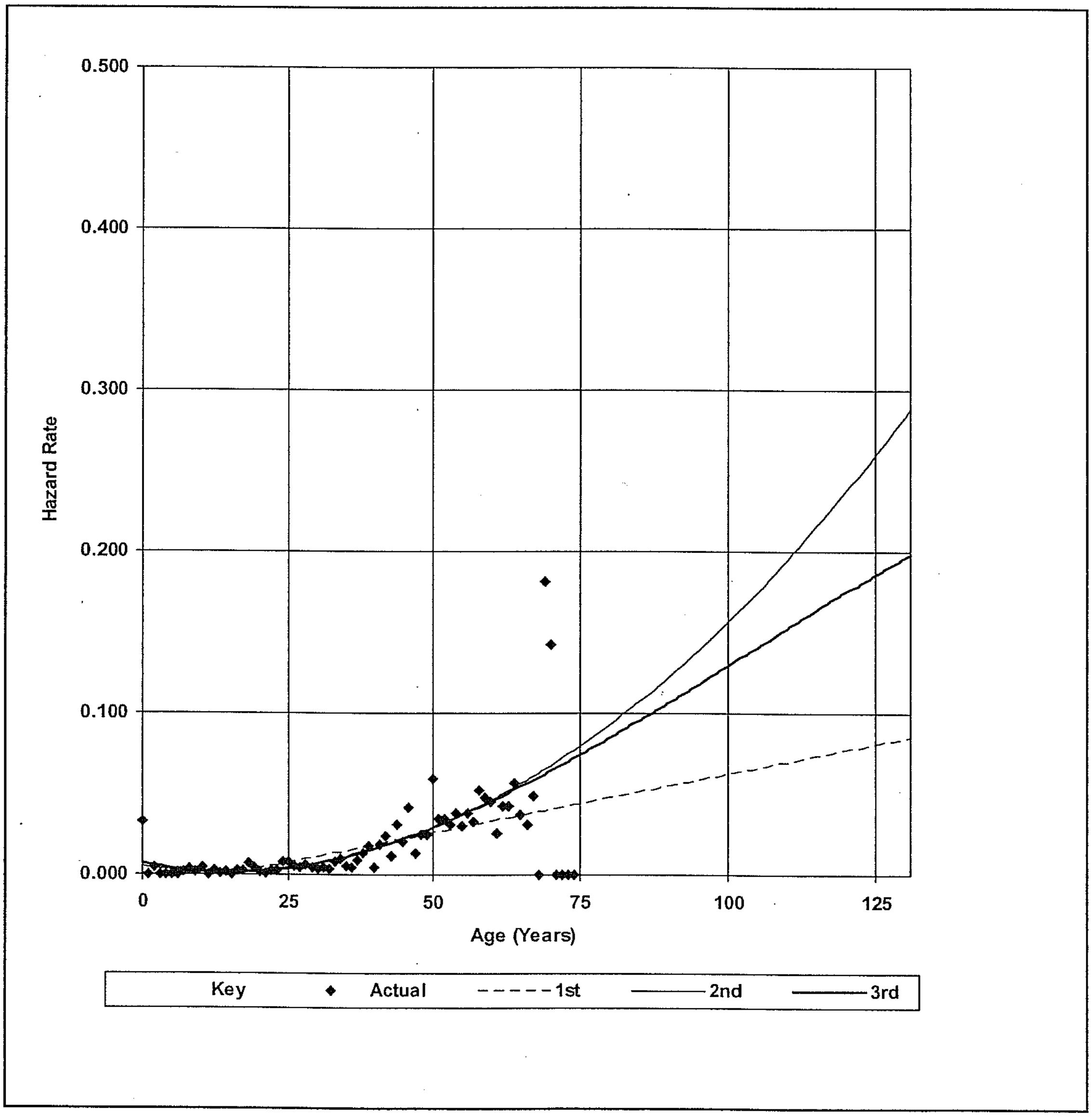
Placement Band: 1936-2011 Observation Band: 1981-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 61.8-L2 2nd: 56.9-R2.5 3rd: 56.8-R2.5



Schedule E

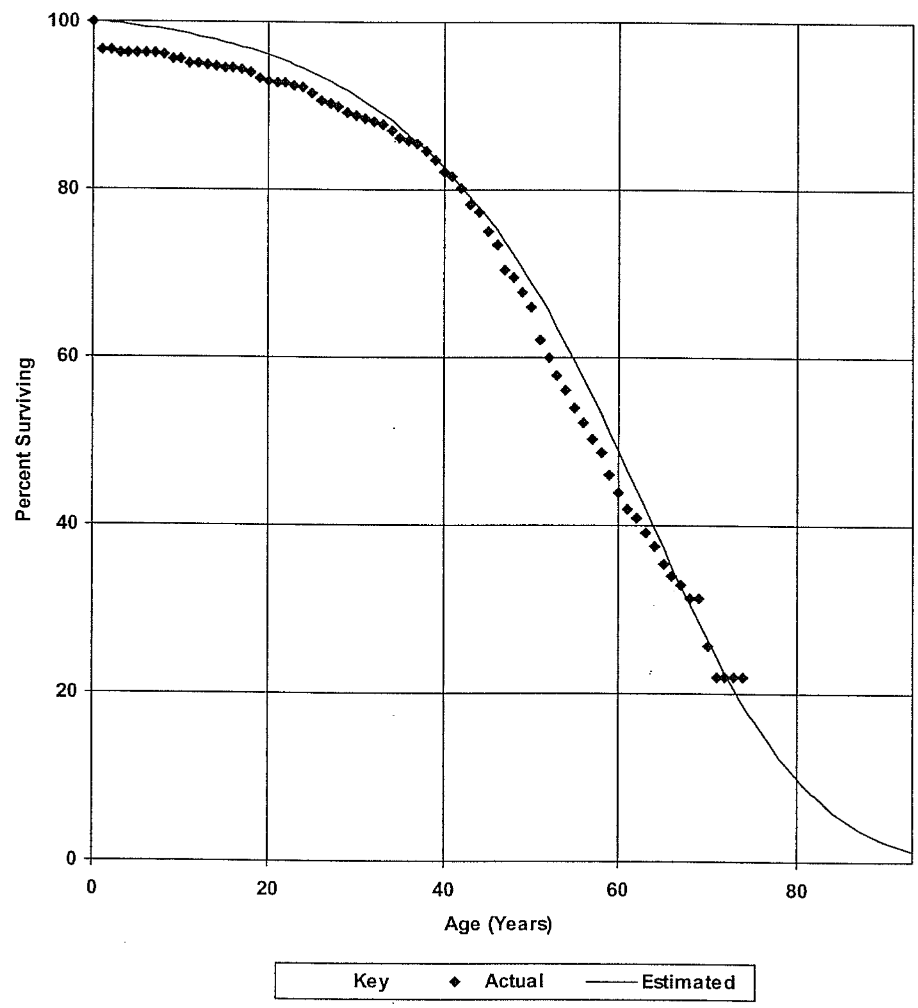
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONO 50kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1936-2011
Observation Band: 1981-2013
57.0-R2.5

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONS 50kV Conventional and Metalclad SF6 Breakers

Placement Band: 1980 - 2008
Observation Band: 1993 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	157	0	0.00000	1.00000	1.00000
0.5	218	2	0.00917	0.99083	1.00000
1.5	369	2	0.00542	0.99458	0.99083
2.5	531	0	0.00000	1.00000	0.98546
3.5	683	3	0.00439	0.99561	0.98546
4.5	751	1	0.00133	0.99867	0.98113
5.5	924	0	0.00000	1.00000	0.97982
6.5	927	5	0.00539	0.99461	0.97982
7.5	894	2	0.00224	0.99776	0.97454
8.5	914	7	0.00766	0.99234	0.97236
9.5	901	5	0.00555	0.99445	0.96491
10.5	915	8	0.00874	0.99126	0.95955
11.5	904	17	0.01881	0.98119	0.95116
12.5	879	21	0.02389	0.97611	0.93328
13.5	850	3	0.00353	0.99647	0.91098
14.5	847	3	0.00354	0.99646	0.90777
15.5	835	10	0.01198	0.98802	0.90455
16.5	797	10	0.01255	0.98745	0.89372
17.5	779	7	0.00899	0.99101	0.88250
18.5	764	13	0.01702	0.98298	0.87457
19.5	748	11	0.01471	0.98529	0.85969
20.5	713	22	0.03086	0.96914	0.84705
21.5	645	16	0.02481	0.97519	0.82091
22.5	502	19	0.03785	0.96215	0.80055
23.5	340	20	0.05882	0.94118	0.77025
24.5	212	11	0.05189	0.94811	0.72494
25.5	181	6	0.03315	0.96685	0.68733
26.5	47	2	0.04255	0.95745	0.66454
27.5	43	1	0.02326	0.97674	0.63626
28.5	38	4	0.10526	0.89474	0.62147
29.5	16	0	0.00000	1.00000	0.55605
30.5	15	3	0.20000	0.80000	0.55605
31.5	0	0	0.00000	1.00000	0.44484

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONS 50kV Conventional and Metalclad SF6 Breakers

T-Cut: None
Placement Band: 1980-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1993-1997	96.1	188.6	R5*	0.67	41.4	S1.5	0.79	189.4	R5*	0.61
1994-1998	96.7	139.7	R0.5	0.75	46.8	S1.5	0.74	191.1	R5*	0.52
1995-1999	91.0	45.9	L1.5*	1.88	34.3	S1.5	1.88	179.0	R3*	0.95
1996-2000	81.4	33.4	L1.5*	2.77	27.3	S1.5	3.01	163.4	R1*	1.28
1997-2001	79.5	30.9	L1.5*	3.03	28.5	S1*	3.28	157.9	R0.5*	1.58
1998-2002	80.3	33.0	L1.5*	3.02	114.8	O3*	2.54	160.6	R1*	0.97
1999-2003	80.6	33.6	L1*	3.96	151.1	SC*	1.73	161.8	R1*	0.75
2000-2004	83.3	42.0	L0.5	5.13	165.5	R1*	0.77	167.8	R1.5*	0.58
2001-2005	78.6	43.0	L0.5	2.16	149.1	SC*	1.48	154.9	R0.5*	1.48
2002-2006	84.4	54.0	L0.5	1.57	163.6	R1*	1.17	171.3	R2*	1.10
2003-2007	87.8	66.3	L0.5	1.55	173.3	R2*	0.94	178.7	R3*	1.09
2004-2008	90.1	64.7	L1.5*	1.19	54.8	S1*	1.30	41.4	R3*	1.77
2005-2009	85.6	69.2	L1	1.66	51.7	S1	1.13	51.1	S1	1.13
2006-2010	79.0	45.3	L2*	2.63	36.6	S2*	3.21	143.5	SC*	2.09
2007-2011	0.0	33.6	L3*	9.63	28.3	R3*	8.10	28.3	R4*	7.13
2008-2012	0.0	33.6	L3*	9.58	29.2	R3*	8.19	29.3	S3	7.54
2009-2013	44.8	32.2	S1.5*	2.81	29.5	R2.5	3.17	29.6	R2.5	3.45

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONS 50kV Conventional and Metalclad SF6 Breakers

T-Cut: None
Placement Band: 1980-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Dispersion	First Degree Conf. Index	Second Degree Average Life	Second Degree Dispersion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Dispersion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1993-2013	44.5	36.2	L1.5*	2.99	30.5	R2	1.39	29.3	R3 *	1.53
1995-2013	44.7	35.9	L2*	2.85	30.3	R2	1.82	29.2	R3 *	1.55
1997-2013	44.3	35.8	L2*	3.15	29.6	R2	2.65	28.9	R2.5 *	1.57
1999-2013	44.3	35.6	L2*	2.98	29.2	R2	3.89	28.4	R2.5 *	2.00
2001-2013	44.5	35.6	L2*	3.85	29.3	R2	3.01	28.8	R3 *	1.64
2003-2013	46.9	35.4	S1.5*	2.66	30.3	R3 *	2.10	30.0	R3	1.71
2005-2013	47.7	35.0	L3*	2.08	30.7	R3 *	1.87	30.6	S3 *	1.65
2007-2013	47.8	34.4	L3*	2.28	30.6	S3 *	1.94	30.6	S3 *	1.92
2009-2013	44.8	32.2	S1.5*	2.81	29.5	R2.5	3.17	29.6	R2.5	3.45
2011-2013	40.9	31.0	L3*	1.37	29.2	R3 *	2.41	29.5	S3 *	2.11
2013-2013	0.0	32.2	L2*	53.82	56.4	O4 *	53.77	100.8	O4 *	53.07

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONS 50kV Conventional and Metalclad SF6 Breakers

T-Cut: None

Placement Band: 1980-2008

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1993-1994	88.0	192.0	SQ*	5.60	29.1	R2.5	5.14	188.0	R5 *	4.44
1993-1996	95.9	190.0	R5*	0.81	33.7	S2	0.95	188.2	R5 *	0.82
1993-1998	95.8	191.7	S6*	0.52	35.9	R2.5	0.91	188.3	R5 *	0.79
1993-2000	82.8	37.4	L1.5*	2.00	25.9	S2	2.83	165.2	R1 *	1.24
1993-2002	82.3	35.0	L1.5*	2.42	30.4	S1 *	3.02	164.0	R1 *	1.02
1993-2004	84.4	40.2	L1.5*	2.72	129.3	SC *	2.14	168.2	R1.5 *	0.58
1993-2006	82.3	44.4	L1	2.06	157.0	R0.5 *	1.27	168.6	R1.5 *	0.87
1993-2008	81.8	54.5	L0.5	1.79	170.1	R1.5 *	1.21	171.9	R2 *	1.36
1993-2010	73.9	45.3	L1	1.28	45.5	L1	1.26	132.0	SC *	1.04
1993-2012	0.0	37.1	L1.5*	10.71	30.4	R2	8.58	28.7	R3 *	7.39
1993-2013	44.5	36.2	L1.5*	2.99	30.5	R2	1.39	29.3	R3 *	1.53

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONS 50kV Conventional and Metalclad SF6 Breakers

T-Cut: None

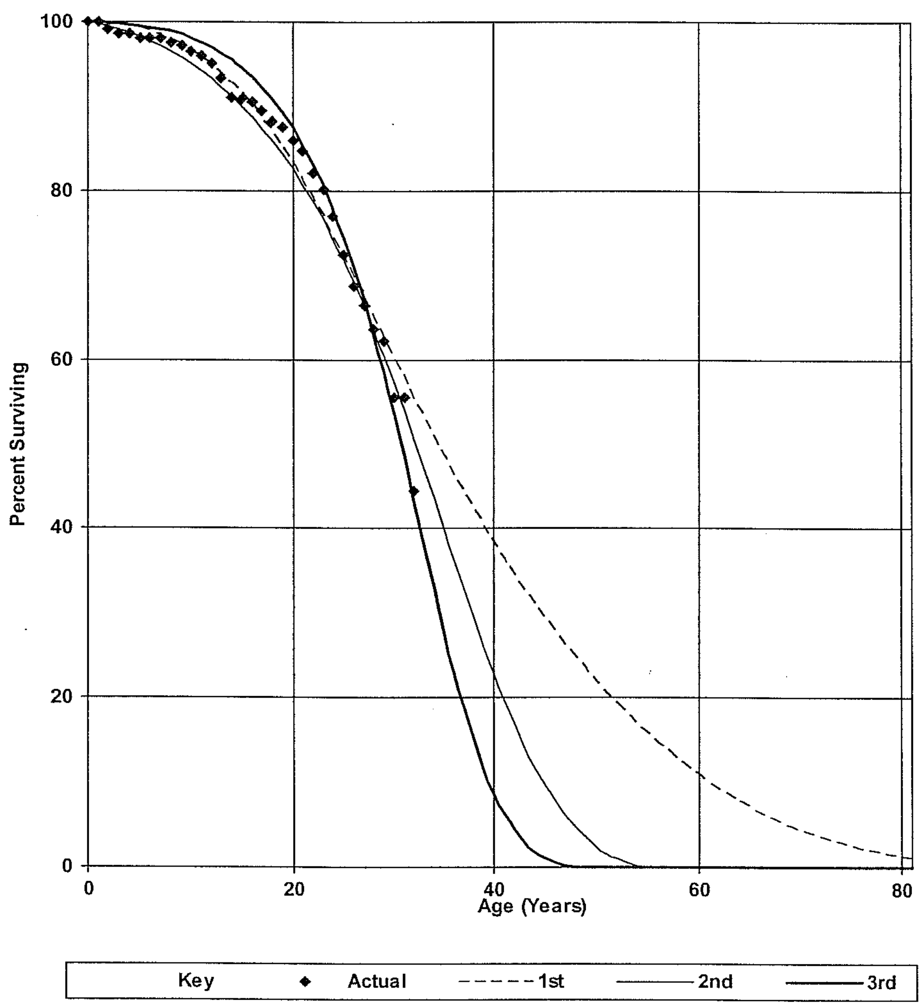
Placement Band: 1980-2008 Observation Band: 1993-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 36.2-L1.5 2nd: 30.5-R2 3rd: 29.3-R3



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONS 50kV Conventional and Metalclad SF6 Breakers

T-Cut: None

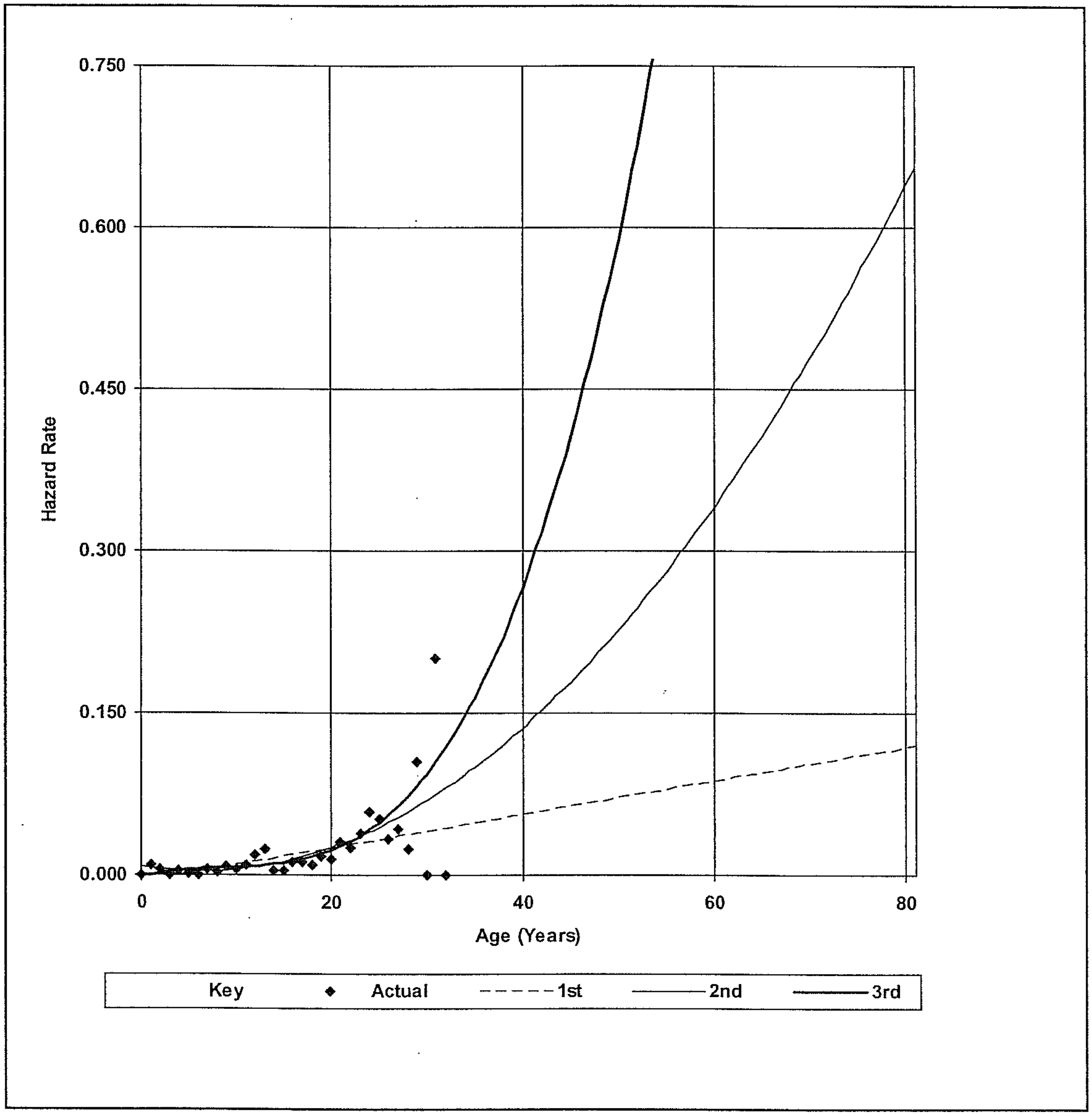
Placement Band: 1980-2008 Observation Band: 1993-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 36.2-L1.5 2nd: 30.5-R2 3rd: 29.3-R3



Schedule E

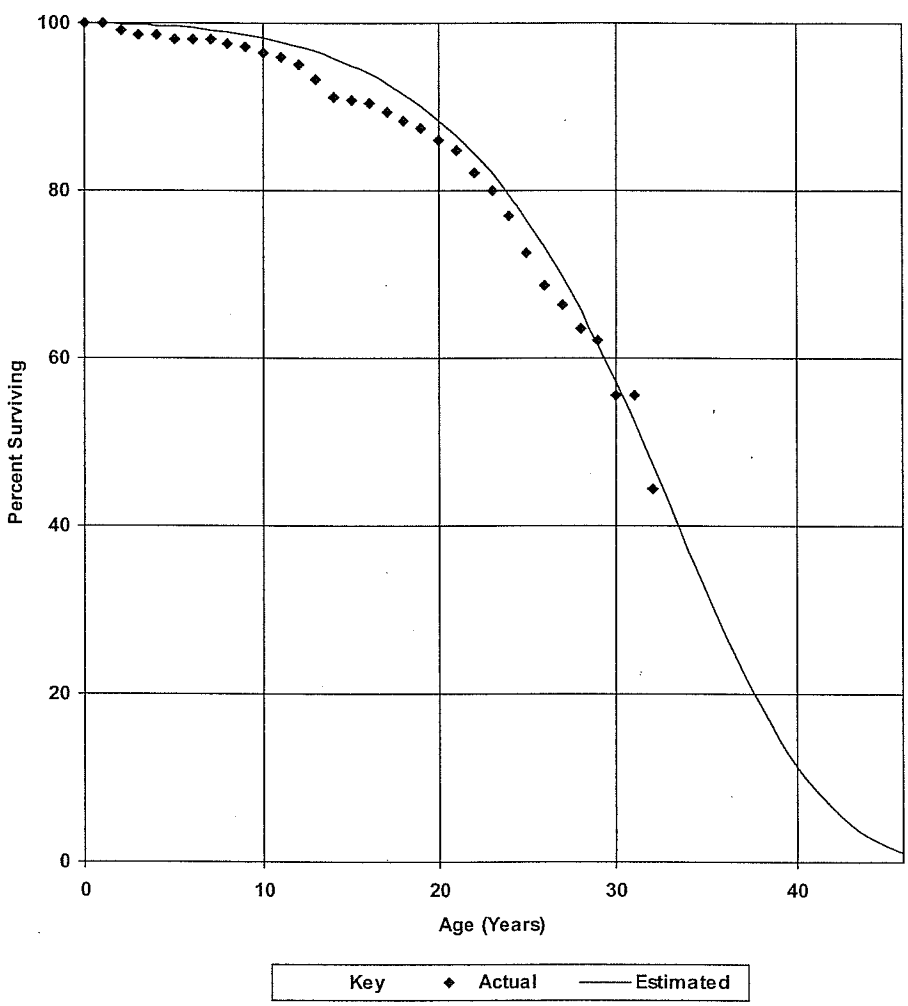
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONS 50kV Conventional and Metalclad SF6 Breakers

T-Cut: None
Placement Band: 1980-2008
Observation Band: 1993-2013
30.0-R3

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONV 50kV Conv. and Metalclad Vacuum Breakers

Placement Band: 1986 - 2013
Observation Band: 1987 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	196	0	0.00000	1.00000	1.00000
0.5	215	2	0.00930	0.99070	1.00000
1.5	201	1	0.00498	0.99502	0.99070
2.5	200	1	0.00500	0.99500	0.98577
3.5	209	0	0.00000	1.00000	0.98084
4.5	192	0	0.00000	1.00000	0.98084
5.5	192	0	0.00000	1.00000	0.98084
6.5	201	0	0.00000	1.00000	0.98084
7.5	180	0	0.00000	1.00000	0.98084
8.5	109	0	0.00000	1.00000	0.98084
9.5	96	1	0.01042	0.98958	0.98084
10.5	86	0	0.00000	1.00000	0.97062
11.5	74	0	0.00000	1.00000	0.97062
12.5	74	0	0.00000	1.00000	0.97062
13.5	69	0	0.00000	1.00000	0.97062
14.5	67	0	0.00000	1.00000	0.97062
15.5	45	5	0.11111	0.88889	0.97062
16.5	40	1	0.02500	0.97500	0.86278
17.5	35	4	0.11429	0.88571	0.84121
18.5	17	0	0.00000	1.00000	0.74507
19.5	17	0	0.00000	1.00000	0.74507
20.5	17	0	0.00000	1.00000	0.74507
21.5	16	0	0.00000	1.00000	0.74507
22.5	16	2	0.12500	0.87500	0.74507
23.5	14	0	0.00000	1.00000	0.65194
24.5	14	0	0.00000	1.00000	0.65194
25.5	14	0	0.00000	1.00000	0.65194
26.5	14	6	0.42857	0.57143	0.65194
27.5	0	0	0.00000	1.00000	0.37253

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONV 50kV Conv. and Metalclad Vacuum Breakers

T-Cut: None

Placement Band: 1986-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-1991	90.9	164.1	R1 *	6.96	7.9	R2 *	4.24	171.3	R2 *	4.18
1988-1992	100.0				No Retirements					
1989-1993	100.0				No Retirements					
1990-1994	100.0				No Retirements					
1991-1995	100.0				No Retirements					
1992-1996	100.0				No Retirements					
1993-1997	100.0				No Retirements					
1994-1998	100.0				No Retirements					
1995-1999	100.0				No Retirements					
1996-2000	100.0				No Retirements					
1997-2001	100.0				No Retirements					
1998-2002	26.7	21.4	L1.5 *	33.01	16.3	R2 *	30.08	16.0	R3 *	33.57
1999-2003	61.3	23.0	L1.5 *	6.92	19.6	R2.5	6.66	18.7	R3	7.39
2000-2004	61.3	24.9	L1.5 *	7.84	22.4	S1	8.11	128.4	SC *	7.31
2001-2005	72.5	26.9	L1.5 *	4.16	26.2	L1.5 *	4.02	127.8	SC *	7.48
2002-2006	74.3	29.2	L1.5 *	3.99	39.7	O3 *	4.24	127.4	SC *	8.25
2003-2007	100.0				No Retirements					
2004-2008	100.0				No Retirements					
2005-2009	74.4	39.0	L1.5 *	3.32	29.6	S3 *	3.48	27.6	S4 *	4.96
2006-2010	62.0	37.4	L1.5 *	7.56	30.5	S2	8.90	97.5	O4 *	7.94
2007-2011	13.8	29.6	L1.5 *	29.39	27.8	S1.5 *	30.24	106.7	O4 *	24.37
2008-2012	15.7	31.3	L2 *	30.55	29.9	S1 *	31.00	105.8	O4 *	23.99
2009-2013	35.3	24.0	L2 *	11.10	23.6	R3 *	8.14	24.3	S3	7.04

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONV 50kV Conv. and Metalclad Vacuum Breakers

T-Cut: None
Placement Band: 1986-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-2013	37.3	28.1	L2 *	6.42	24.9	R3 *	6.55	24.9	R3	6.18
1989-2013	37.6	27.8	L2 *	6.77	25.1	S3 *	6.63	25.2	R4 *	6.17
1991-2013	37.6	27.8	L2 *	6.72	25.1	S3 *	6.62	25.2	R4 *	6.16
1993-2013	37.6	27.8	L2 *	6.74	25.1	S3 *	6.62	25.2	R4 *	6.16
1995-2013	37.6	27.8	L2 *	6.81	25.1	S3 *	6.62	25.2	R4 *	6.16
1997-2013	37.4	27.7	L2 *	6.82	25.1	S3 *	6.55	25.1	R4 *	6.14
1999-2013	37.4	27.4	L2 *	7.14	25.0	S3 *	6.58	25.1	R4 *	6.14
2001-2013	37.4	27.0	L2 *	7.69	25.0	S3 *	6.72	25.0	R4 *	6.16
2003-2013	41.2	28.6	L2 *	9.11	25.7	S3 *	7.60	26.1	S4 *	5.96
2005-2013	36.1	27.7	L2 *	7.02	25.4	S3 *	5.82	26.0	R4 *	7.27
2007-2013	36.0	26.2	L2 *	8.54	24.8	S3 *	6.49	25.5	R4 *	6.54
2009-2013	35.3	24.0	L2 *	11.10	23.6	R3 *	8.14	24.3	S3	7.04
2011-2013	44.4	23.1	S1.5 *	19.74	23.2	R3 *	15.92	24.6	R4 *	12.20
2013-2013	57.1	19.0	L3 *	43.99	19.0	R2.5 *	39.47	23.4	R5 *	26.58

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONV 50kV Conv. and Metalclad Vacuum Breakers

T-Cut: None

Placement Band: 1986-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-1988	90.9	148.1	SC *	14.81	172.8	R2 *	3.70	172.8	R2 *	3.70
1987-1990	90.9	160.9	R1 *	8.34	6.6	R2.5 *	4.14	172.8	R2 *	3.85
1987-1992	90.9	165.5	R1 *	6.16	9.3	R2 *	4.11	170.4	R2 *	4.41
1987-1994	92.9	171.1	R2 *	5.40	12.7	R2.5 *	3.93	174.8	R2.5 *	3.98
1987-1996	92.9	174.5	R2.5 *	4.05	15.7	R2.5 *	3.25	174.8	R2.5 *	3.78
1987-1998	92.9	176.0	R2.5 *	3.51	18.5	R2.5 *	3.20	174.2	R2 *	3.96
1987-2000	93.5	177.4	R3 *	3.50	21.8	R2.5 *	3.32	175.7	R2.5 *	3.87
1987-2002	69.5	25.5	L1	5.36	17.1	R2.5 *	4.61	16.4	R3 *	3.46
1987-2004	72.2	31.7	L1	4.03	21.4	R2.5	2.86	125.5	SC *	3.32
1987-2006	75.8	38.9	L1	4.33	27.2	R2	3.99	153.9	SC *	3.46
1987-2008	78.3	47.3	L1	4.78	34.6	S1	4.81	160.6	R1 *	3.35
1987-2010	65.7	36.2	L1.5 *	4.57	28.4	R2.5	4.62	130.0	SC *	3.65
1987-2012	59.3	34.6	L1.5 *	6.33	29.7	S1.5	6.26	126.4	SC *	3.79
1987-2013	37.3	28.1	L2 *	6.42	24.9	R3 *	6.55	24.9	R3	6.18

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONV 50kV Conv. and Metalclad Vacuum Breakers

T-Cut: None

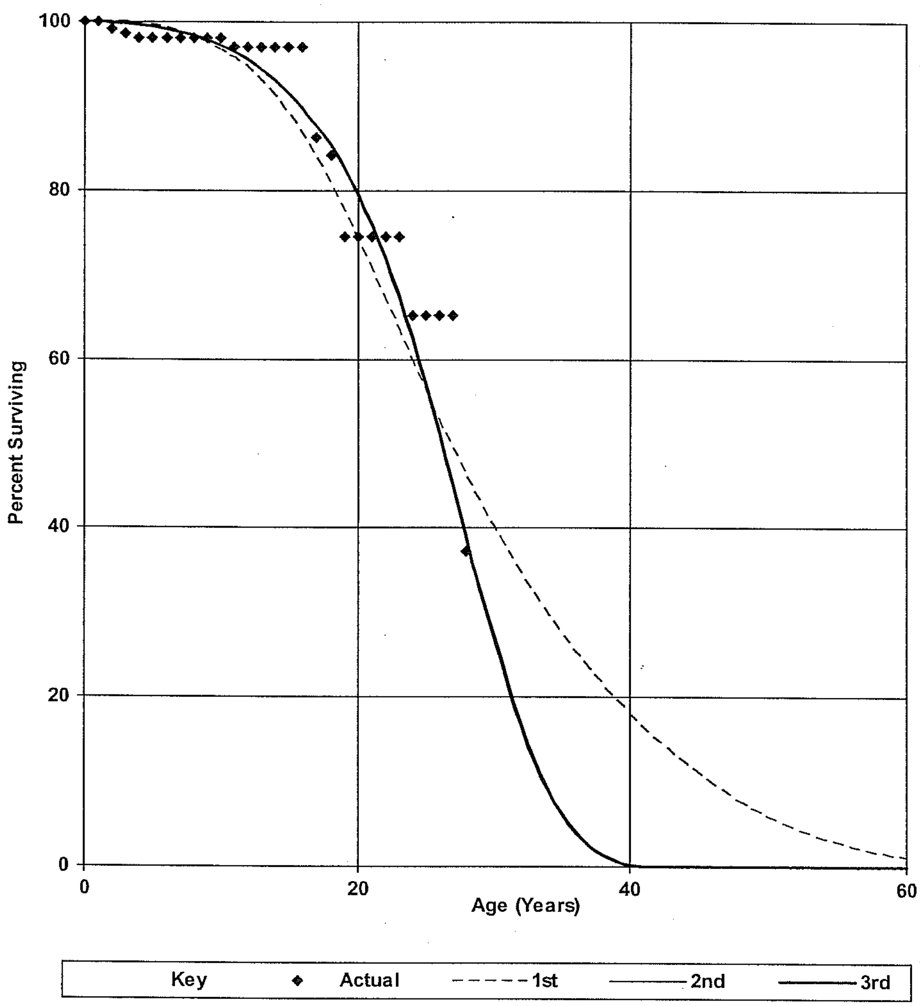
Placement Band: 1986-2013 Observation Band: 1987-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 28.1-L2 2nd: 24.9-R3 3rd: 24.9-R3



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONV 50kV Conv. and Metalclad Vacuum Breakers

T-Cut: None

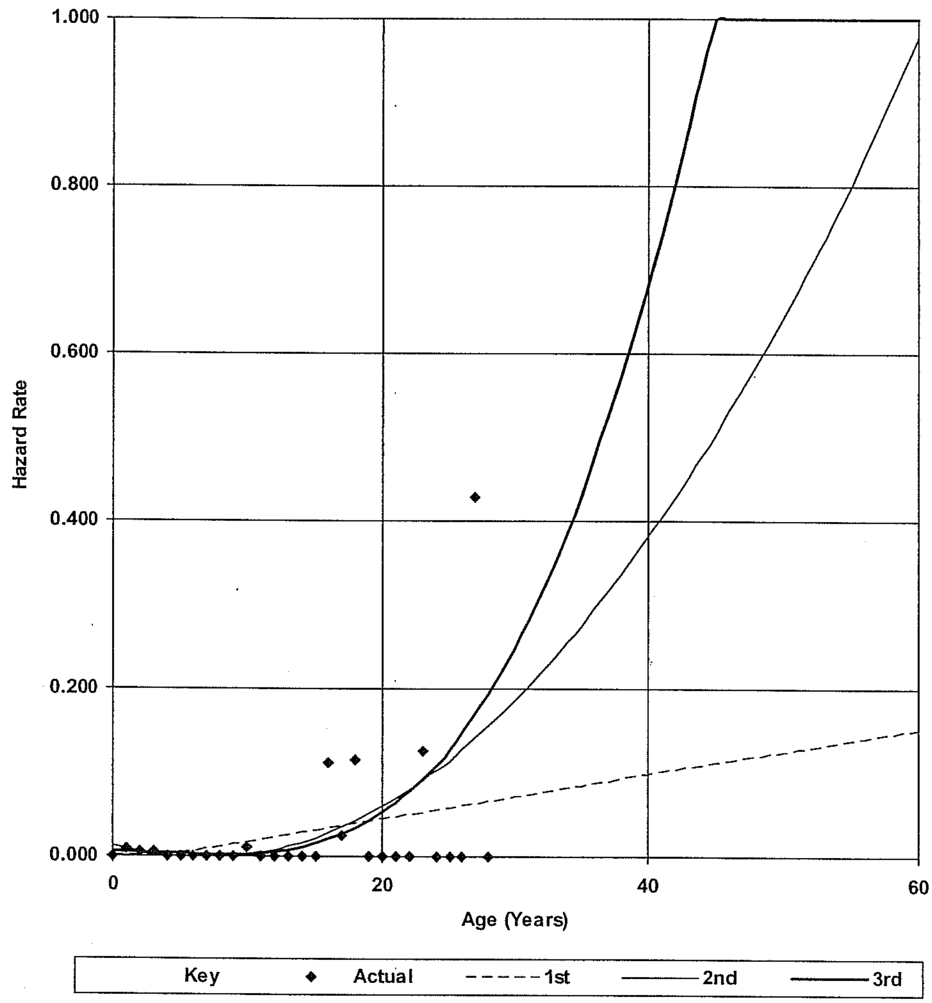
Placement Band: 1986-2013 Observation Band: 1987-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 28.1-L2 2nd: 24.9-R3 3rd: 24.9-R3



Schedule E

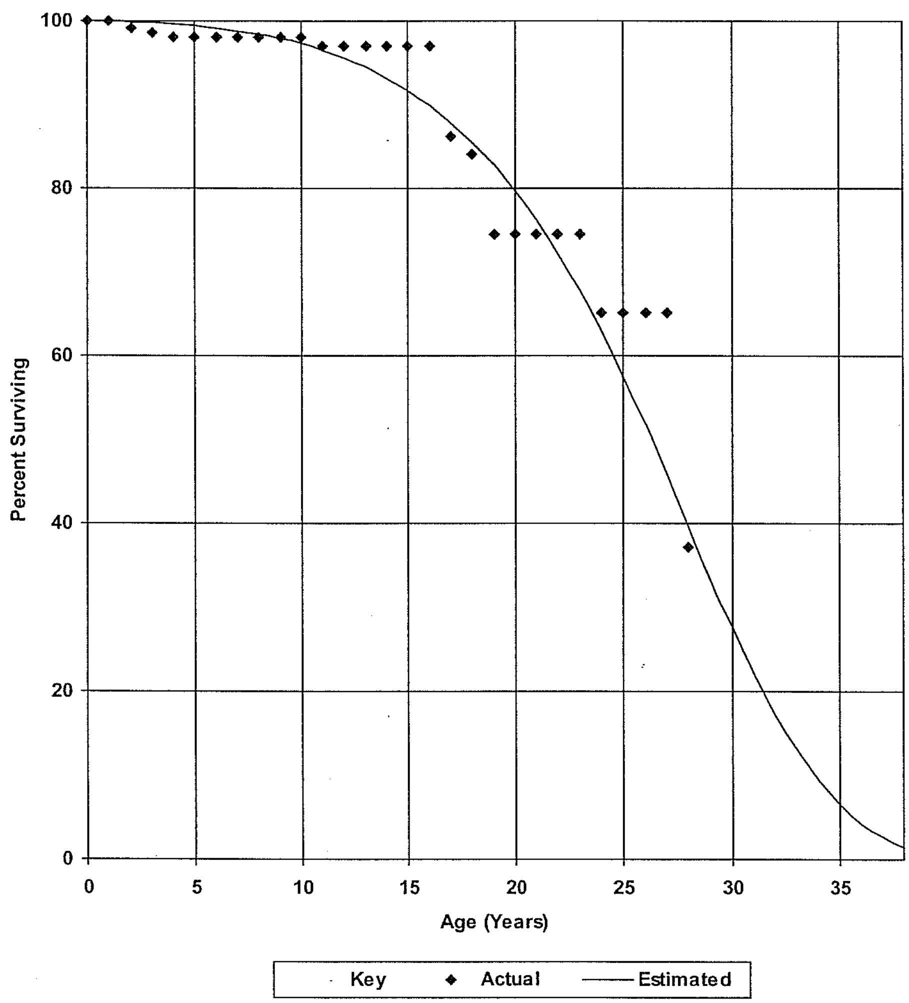
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 050CONV 50kV Conv. and Metalclad Vacuum Breakers

T-Cut: None
Placement Band: 1986-2013
Observation Band: 1987-2013
25.0-R3

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

Placement Band: 1939 - 2013
Observation Band: 1980 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	464	3	0.00647	0.99353	1.00000
0.5	415	2	0.00482	0.99518	0.99353
1.5	344	0	0.00000	1.00000	0.98875
2.5	260	0	0.00000	1.00000	0.98875
3.5	222	0	0.00000	1.00000	0.98875
4.5	202	0	0.00000	1.00000	0.98875
5.5	188	1	0.00532	0.99468	0.98875
6.5	187	5	0.02674	0.97326	0.98349
7.5	162	1	0.00617	0.99383	0.95719
8.5	176	3	0.01705	0.98295	0.95128
9.5	193	3	0.01554	0.98446	0.93507
10.5	228	1	0.00439	0.99561	0.92053
11.5	242	1	0.00413	0.99587	0.91649
12.5	268	1	0.00373	0.99627	0.91271
13.5	270	0	0.00000	1.00000	0.90930
14.5	278	0	0.00000	1.00000	0.90930
15.5	275	0	0.00000	1.00000	0.90930
16.5	270	4	0.01481	0.98519	0.90930
17.5	277	1	0.00361	0.99639	0.89583
18.5	294	1	0.00340	0.99660	0.89260
19.5	307	3	0.00977	0.99023	0.88956
20.5	332	2	0.00602	0.99398	0.88087
21.5	352	8	0.02273	0.97727	0.87556
22.5	330	4	0.01212	0.98788	0.85566
23.5	334	3	0.00898	0.99102	0.84529
24.5	336	4	0.01190	0.98810	0.83770
25.5	341	3	0.00880	0.99120	0.82773
26.5	356	1	0.00281	0.99719	0.82044
27.5	419	3	0.00716	0.99284	0.81814
28.5	430	5	0.01163	0.98837	0.81228
29.5	480	6	0.01250	0.98750	0.80284
30.5	512	19	0.03711	0.96289	0.79280
31.5	559	8	0.01431	0.98569	0.76338
32.5	597	4	0.00670	0.99330	0.75246
33.5	620	2	0.00323	0.99677	0.74741
34.5	632	3	0.00475	0.99525	0.74500
35.5	629	5	0.00795	0.99205	0.74147

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

Placement Band: 1939 - 2013
Observation Band: 1980 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	588	6	0.01020	0.98980	0.73557
37.5	574	7	0.01220	0.98780	0.72807
38.5	572	11	0.01923	0.98077	0.71919
39.5	571	6	0.01051	0.98949	0.70536
40.5	564	8	0.01418	0.98582	0.69795
41.5	554	16	0.02888	0.97112	0.68805
42.5	537	11	0.02048	0.97952	0.66817
43.5	510	31	0.06078	0.93922	0.65449
44.5	464	19	0.04095	0.95905	0.61470
45.5	437	28	0.06407	0.93593	0.58953
46.5	390	12	0.03077	0.96923	0.55176
47.5	376	26	0.06915	0.93085	0.53478
48.5	345	20	0.05797	0.94203	0.49780
49.5	325	25	0.07692	0.92308	0.46895
50.5	300	19	0.06333	0.93667	0.43287
51.5	278	14	0.05036	0.94964	0.40546
52.5	263	12	0.04563	0.95437	0.38504
53.5	247	21	0.08502	0.91498	0.36747
54.5	216	11	0.05093	0.94907	0.33623
55.5	198	7	0.03535	0.96465	0.31910
56.5	183	3	0.01639	0.98361	0.30782
57.5	176	4	0.02273	0.97727	0.30278
58.5	169	5	0.02959	0.97041	0.29590
59.5	160	1	0.00625	0.99375	0.28714
60.5	151	4	0.02649	0.97351	0.28535
61.5	121	4	0.03306	0.96694	0.27779
62.5	111	1	0.00901	0.99099	0.26861
63.5	93	1	0.01075	0.98925	0.26619
64.5	74	0	0.00000	1.00000	0.26332
65.5	45	0	0.00000	1.00000	0.26332
66.5	22	3	0.13636	0.86364	0.26332
67.5	9	2	0.22222	0.77778	0.22742
68.5	6	1	0.16667	0.83333	0.17688
69.5	5	0	0.00000	1.00000	0.14740
70.5	5	0	0.00000	1.00000	0.14740
71.5	5	0	0.00000	1.00000	0.14740
72.5	3	0	0.00000	1.00000	0.14740

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

Placement Band: 1939 - 2013
Observation Band: 1980 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	0	0	0.00000	1.00000	0.14740

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

T-Cut: None

Placement Band: 1939-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1980-1984	99.5	182.4	R4 *	0.24	197.2	SQ *	0.30	197.3	SQ *	0.29
1981-1985	100.0				No Retirements					
1982-1986	97.2	138.4	S0.5 *	1.05	190.0	R5 *	1.31	190.3	R5 *	1.61
1983-1987	91.4	127.0	S0 *	1.05	186.1	R4 *	1.12	188.5	R5 *	1.17
1984-1988	83.7	161.6	R1 *	2.28	173.0	R2 *	1.61	168.4	R1.5 *	3.31
1985-1989	78.5	112.5	SC	2.36	149.5	SC *	2.65	162.1	R1 *	2.47
1986-1990	79.7	120.0	SC	2.00	164.2	R1 *	2.52	162.0	R1 *	2.42
1987-1991	73.6	85.4	L0.5	2.56	71.7	R1	1.92	145.1	SC *	1.76
1988-1992	66.8	67.1	L1.5 *	4.47	58.1	R2	2.94	93.8	O3 *	2.68
1989-1993	52.7	56.7	L2 *	3.83	54.5	S3 *	1.94	54.4	S3 *	1.95
1990-1994	29.5	50.1	L3 *	4.67	48.9	R3 *	3.92	48.2	R4 *	3.55
1991-1995	0.0	45.4	L3 *	4.36	45.8	R3 *	9.13	44.2	R3 *	7.43
1992-1996	15.1	44.1	L3 *	8.85	45.5	R3 *	3.50	45.4	R3 *	2.54
1993-1997	10.5	42.6	L3 *	10.09	43.9	R3 *	4.56	45.1	R3 *	2.44
1994-1998	7.9	42.5	L3 *	14.06	40.4	R1.5 *	10.40	43.2	R2.5 *	5.55
1995-1999	9.7	42.2	L3 *	10.88	39.0	R1 *	8.95	40.5	R1.5	6.08
1996-2000	16.1	43.8	L3 *	8.14	40.3	R1	7.39	40.4	R1	7.11
1997-2001	15.6	43.8	L2 *	8.01	36.8	SC	10.66	36.7	SC	10.94
1998-2002	20.7	43.9	L0.5	5.80	36.1	SC	9.81	38.1	O2 *	11.36
1999-2003	30.7	46.8	L0.5	4.58	42.6	SC	7.28	66.8	O4 *	11.00
2000-2004	41.3	50.5	O2	7.18	48.7	O2	7.49	79.2	O4 *	10.83
2001-2005	40.0	51.5	O2	6.43	47.8	O2	7.56	77.7	O4 *	13.09
2002-2006	45.0	61.2	O2	4.41	84.6	O4 *	3.34	100.2	O4 *	6.20
2003-2007	42.7	66.3	L0	7.21	98.3	O3 *	8.37	115.7	O3 *	8.92
2004-2008	40.2	64.0	O2	6.95	105.1	O3 *	6.70	111.9	O3 *	8.39
2005-2009	38.3	66.2	L1.5 *	5.29	66.5	L1.5 *	5.28	64.9	L1.5 *	5.14
2006-2010	37.0	61.8	L0.5	4.72	75.2	O3 *	4.28	54.1	S-.5 *	3.89
2007-2011	14.8	45.8	O2	11.69	66.0	O4 *	8.15	41.7	L0 *	7.14
2008-2012	3.2	34.0	O2	15.62	39.8	O3 *	10.39	41.2	O3 *	11.45
2009-2013	0.1	27.4	O2	20.61	26.9	L0.5 *	14.67	27.5	L0.5 *	15.37

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

T-Cut: None
Placement Band: 1939-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1980-2013	14.7	51.5	L2 *	4.56	50.5	S1	3.97	75.4	O3 *	4.85
1982-2013	14.2	50.4	L1.5 *	4.40	49.5	S0.5	3.82	74.2	O3 *	5.06
1984-2013	13.5	48.9	L1.5 *	4.04	48.3	L1.5 *	3.61	72.5	O3 *	5.05
1986-2013	12.7	47.0	L1.5 *	3.62	46.9	L1.5 *	3.49	70.5	O3 *	5.05
1988-2013	12.1	45.3	L1 *	3.37	45.5	L1 *	3.62	68.7	O3 *	5.32
1990-2013	11.3	43.4	L1	2.88	44.4	L1 *	3.63	67.1	O3 *	5.52
1992-2013	10.2	41.3	L1	2.58	43.6	L1 *	3.77	64.3	O3 *	6.05
1994-2013	9.7	40.0	L0.5	2.28	43.7	L0.5 *	3.62	61.9	O3 *	5.99
1996-2013	10.0	39.7	L0	2.01	46.3	O2 *	3.21	61.3	O4 *	5.25
1998-2013	10.3	39.4	O2	2.19	48.8	O3 *	2.79	58.0	O4 *	3.90
2000-2013	10.4	40.2	O2	3.50	53.8	O4 *	2.57	57.8	O4 *	3.17
2002-2013	8.0	39.0	O2	6.52	52.0	O4 *	5.02	55.2	O4 *	6.06
2004-2013	5.5	36.6	O2	9.47	47.1	O4 *	6.21	48.4	O4 *	6.74
2006-2013	3.9	34.6	O2	10.82	41.2	O3 *	6.36	43.6	O3 *	7.60
2008-2013	1.1	29.3	O2	13.68	30.5	L0.5 *	8.05	31.7	L0.5 *	8.86
2010-2013	0.0	24.9	O2	18.20	22.5	L1 *	10.90	23.6	L1 *	12.32
2012-2013	0.0	20.7	O2	13.74	17.0	L1.5 *	14.51	20.4	L1.5 *	10.15

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

T-Cut: None
Placement Band: 1939-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1980-1981	98.9	154.9	R1.5*	0.60	189.2	R5 *	0.66	195.1	SQ *	0.72
1980-1983	99.4	177.2	R3*	0.31	196.6	S6 *	0.38	197.0	SQ *	0.38
1980-1985	99.5	186.0	R4*	0.19	197.5	S6 *	0.24	197.6	S6 *	0.22
1980-1987	94.8	135.1	S0.5*	0.60	184.2	R4 *	0.71	191.1	R5 *	0.69
1980-1989	90.4	126.3	S0	0.77	94.5	S1	0.84	178.5	R2.5 *	1.09
1980-1991	84.7	101.3	L1.5*	1.27	76.2	S1.5	1.04	86.1	L2 *	1.06
1980-1993	61.8	71.0	L2*	2.45	57.2	R3 *	2.28	55.2	R4 *	2.01
1980-1995	0.0	58.5	L3*	8.46	48.2	R2.5 *	7.93	49.0	R4 *	4.64
1980-1997	16.9	54.1	L3*	7.55	46.1	R2.5 *	8.00	48.7	R4 *	2.12
1980-1999	12.6	52.4	L3*	7.94	44.6	R2 *	7.80	47.7	R4 *	1.88
1980-2001	17.2	53.0	L3*	6.90	46.5	R2.5 *	5.17	48.4	R3	1.74
1980-2003	27.4	53.8	L3*	5.19	48.5	R2.5 *	3.38	48.9	R2.5	2.81
1980-2005	35.5	54.6	L2*	4.73	50.3	R2.5	4.11	50.6	R2 *	4.31
1980-2007	38.1	56.1	L2*	4.82	52.9	R2.5	4.61	76.8	O3 *	4.53
1980-2009	29.0	56.2	L2*	4.23	53.9	S1.5	3.88	78.8	O3 *	3.18
1980-2011	23.9	55.6	L2*	4.05	54.2	S1 *	3.94	84.7	O3 *	3.16
1980-2013	14.7	51.5	L2*	4.56	50.5	S1	3.97	75.4	O3 *	4.85

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

T-Cut: None

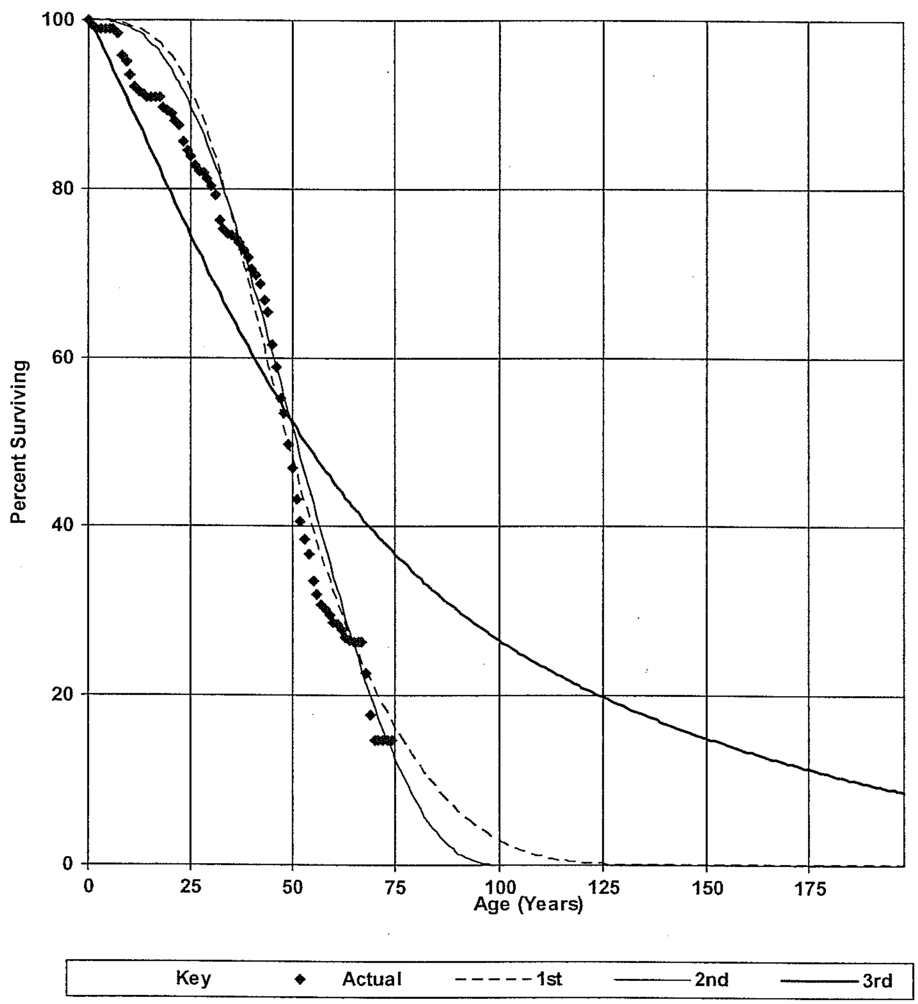
Placement Band: 1939-2013 Observation Band: 1980-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 51.5-L2 2nd: 50.5-S1 3rd: 75.4-O3



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

T-Cut: None

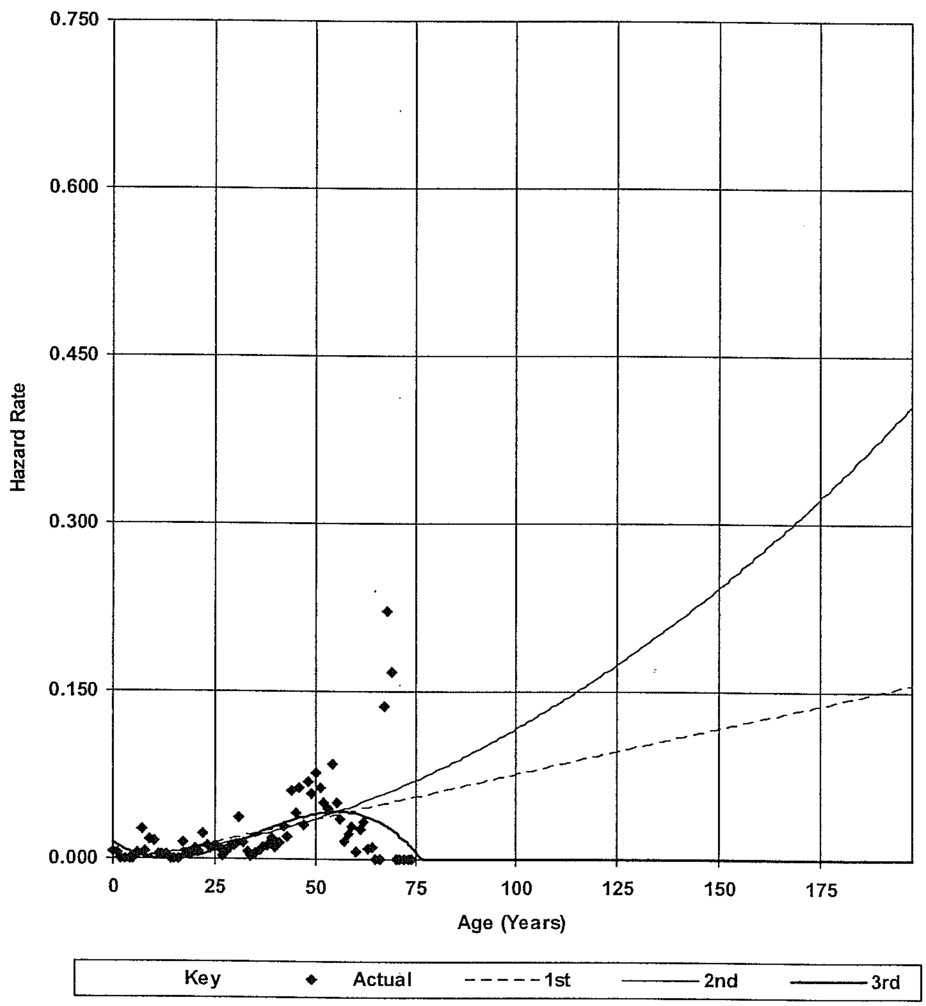
Placement Band: 1939-2013 Observation Band: 1980-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 51.5-L2 2nd: 50.5-S1 3rd: 75.4-O3



Schedule E

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115BRKX 115kV Breakers

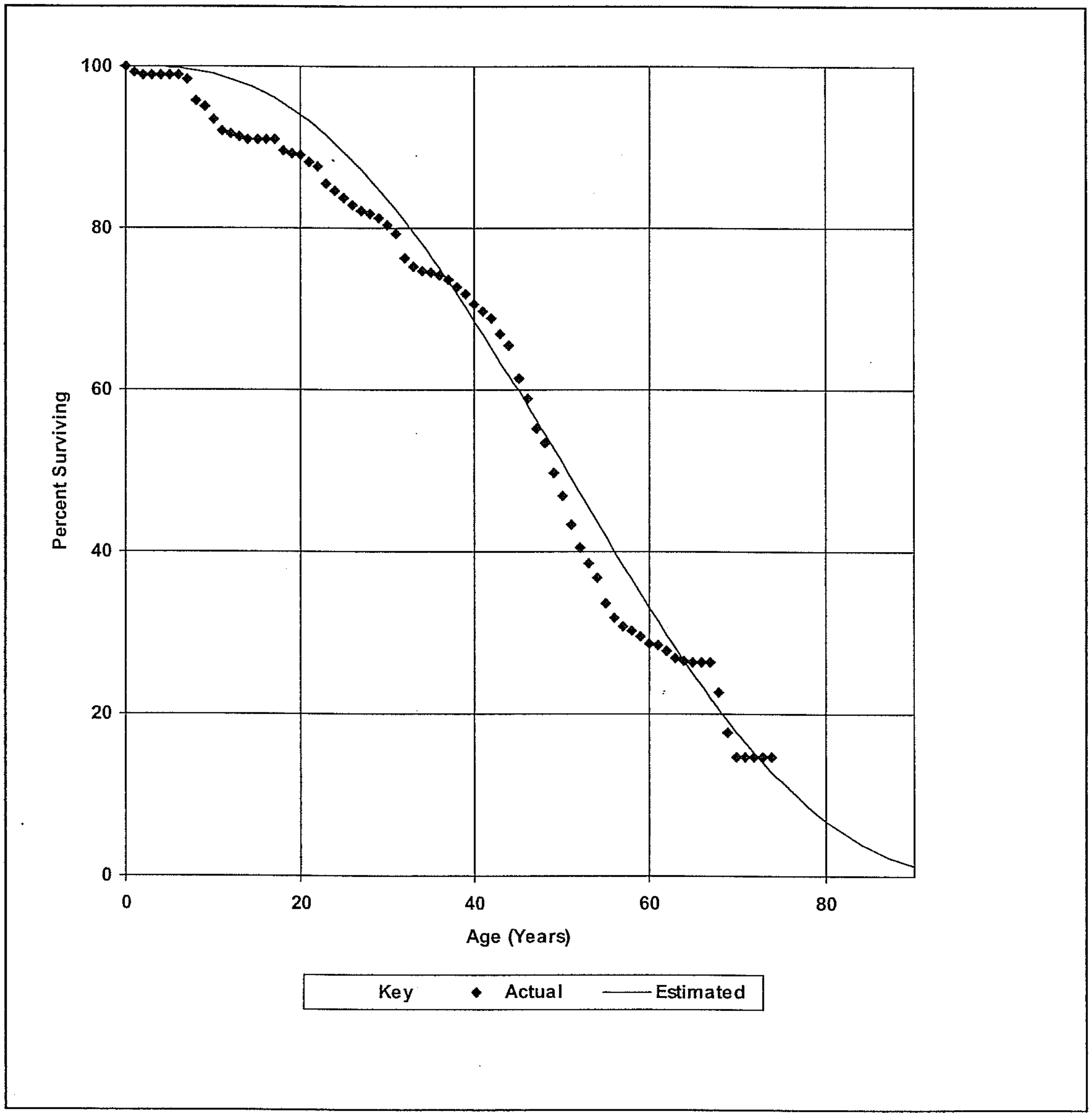
T-Cut: None

Placement Band: 1939-2013

Observation Band: 1980-2013

50.0-S1

Estimated Projection Life Curve



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONO 115kV Conventional Oil Breakers

Placement Band: 1939 - 1982
Observation Band: 1980 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	7	0	0.00000	1.00000	1.00000
0.5	8	0	0.00000	1.00000	1.00000
1.5	8	0	0.00000	1.00000	1.00000
2.5	37	0	0.00000	1.00000	1.00000
3.5	48	0	0.00000	1.00000	1.00000
4.5	52	0	0.00000	1.00000	1.00000
5.5	56	0	0.00000	1.00000	1.00000
6.5	62	0	0.00000	1.00000	1.00000
7.5	64	0	0.00000	1.00000	1.00000
8.5	69	0	0.00000	1.00000	1.00000
9.5	90	0	0.00000	1.00000	1.00000
10.5	126	0	0.00000	1.00000	1.00000
11.5	141	0	0.00000	1.00000	1.00000
12.5	168	0	0.00000	1.00000	1.00000
13.5	171	0	0.00000	1.00000	1.00000
14.5	179	0	0.00000	1.00000	1.00000
15.5	179	0	0.00000	1.00000	1.00000
16.5	179	1	0.00559	0.99441	1.00000
17.5	190	0	0.00000	1.00000	0.99441
18.5	208	1	0.00481	0.99519	0.99441
19.5	221	1	0.00452	0.99548	0.98963
20.5	248	1	0.00403	0.99597	0.98515
21.5	269	0	0.00000	1.00000	0.98118
22.5	284	0	0.00000	1.00000	0.98118
23.5	295	0	0.00000	1.00000	0.98118
24.5	300	1	0.00333	0.99667	0.98118
25.5	309	0	0.00000	1.00000	0.97791
26.5	327	0	0.00000	1.00000	0.97791
27.5	391	3	0.00767	0.99233	0.97791
28.5	402	2	0.00498	0.99502	0.97041
29.5	455	3	0.00659	0.99341	0.96558
30.5	490	14	0.02857	0.97143	0.95921
31.5	543	4	0.00737	0.99263	0.93181
32.5	585	3	0.00513	0.99487	0.92494
33.5	609	0	0.00000	1.00000	0.92020
34.5	624	3	0.00481	0.99519	0.92020
35.5	621	5	0.00805	0.99195	0.91578

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONO 115kV Conventional Oil Breakers

Placement Band: 1939 - 1982
Observation Band: 1980 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	588	6	0.01020	0.98980	0.90840
37.5	574	7	0.01220	0.98780	0.89913
38.5	572	11	0.01923	0.98077	0.88817
39.5	571	6	0.01051	0.98949	0.87109
40.5	564	8	0.01418	0.98582	0.86194
41.5	554	16	0.02888	0.97112	0.84971
42.5	537	11	0.02048	0.97952	0.82517
43.5	510	31	0.06078	0.93922	0.80827
44.5	464	19	0.04095	0.95905	0.75914
45.5	437	28	0.06407	0.93593	0.72805
46.5	390	12	0.03077	0.96923	0.68140
47.5	376	26	0.06915	0.93085	0.66044
48.5	345	20	0.05797	0.94203	0.61477
49.5	325	25	0.07692	0.92308	0.57913
50.5	300	19	0.06333	0.93667	0.53458
51.5	278	14	0.05036	0.94964	0.50072
52.5	263	12	0.04563	0.95437	0.47551
53.5	247	21	0.08502	0.91498	0.45381
54.5	216	11	0.05093	0.94907	0.41523
55.5	198	7	0.03535	0.96465	0.39408
56.5	183	3	0.01639	0.98361	0.38015
57.5	176	4	0.02273	0.97727	0.37392
58.5	169	5	0.02959	0.97041	0.36542
59.5	160	1	0.00625	0.99375	0.35461
60.5	151	4	0.02649	0.97351	0.35239
61.5	121	4	0.03306	0.96694	0.34306
62.5	111	1	0.00901	0.99099	0.33172
63.5	93	1	0.01075	0.98925	0.32873
64.5	74	0	0.00000	1.00000	0.32519
65.5	45	0	0.00000	1.00000	0.32519
66.5	22	3	0.13636	0.86364	0.32519
67.5	9	2	0.22222	0.77778	0.28085
68.5	6	1	0.16667	0.83333	0.21844
69.5	5	0	0.00000	1.00000	0.18203
70.5	5	0	0.00000	1.00000	0.18203
71.5	5	0	0.00000	1.00000	0.18203
72.5	3	0	0.00000	1.00000	0.18203

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONO 115kV Conventional Oil Breakers

Placement Band: 1939 - 1982
Observation Band: 1980 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	0	0	0.00000	1.00000	0.18203

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONO 115kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1939-1982
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1980-1984	99.5	182.4	R4*	0.24	197.2	SQ*	0.30	197.3	SQ*	0.29
1981-1985	100.0				No Retirements					
1982-1986	97.2	138.4	S0.5*	1.05	190.0	R5*	1.31	190.3	R5*	1.61
1983-1987	91.4	127.0	S0*	1.05	186.1	R4*	1.12	188.5	R5*	1.17
1984-1988	87.4	128.7	S-.5	2.04	181.9	R4*	1.59	183.0	R4*	1.80
1985-1989	84.1	100.6	L1*	2.21	173.9	R2*	1.79	177.2	R2.5*	2.06
1986-1990	85.5	106.3	L1	2.48	174.5	R2*	1.61	176.5	R2.5*	1.45
1987-1991	80.1	82.6	L1.5*	1.72	144.9	SC*	1.62	94.1	S0*	1.67
1988-1992	73.4	66.4	L2*	2.63	63.2	S1.5*	2.48	121.4	SC*	5.46
1989-1993	52.7	56.9	L3*	2.08	54.3	S2*	2.00	54.0	S2*	2.39
1990-1994	29.5	51.1	L3*	3.50	37.3	SC*	20.24	48.6	R4*	3.61
1991-1995	0.0	47.4	L3*	7.67	28.0	O3	29.27	45.4	R3*	7.49
1992-1996	15.0	46.7	S3*	4.28	26.4	O3*	36.13	46.5	R4*	2.21
1993-1997	10.4	45.5	L4*	4.30	23.4	O4	40.69	45.8	R4*	1.85
1994-1998	8.2	46.1	L4*	8.28	18.1	O4*	53.09	45.9	R4*	3.80
1995-1999	9.5	46.4	L4*	8.13	19.4	O4	43.34	37.7	R1	11.13
1996-2000	15.9	48.0	S3*	7.52	37.5	R0.5	12.95	25.4	O3	33.55
1997-2001	16.4	49.4	L3*	8.02	40.6	R1	9.04	22.3	O4*	41.19
1998-2002	21.5	53.2	L3*	13.62	49.2	S1	8.92	23.9	O4*	45.82
1999-2003	19.8	53.9	L2*	26.48	65.3	L1.5*	29.43	9.3	O4*	50.00
2000-2004	54.8	60.1	L1.5*	8.10	116.8	O3*	2.71	92.5	O4*	20.80
2001-2005	56.9	65.5	L2*	4.09	124.0	SC*	3.21	25.1	O4*	68.82
2002-2006	63.0	71.7	L2*	4.93	135.7	SC*	3.33	25.7	O4*	70.75
2003-2007	61.9	74.3	L2*	4.60	138.3	SC*	3.79	9.0	O4*	81.63
2004-2008	57.5	65.3	O2	15.86	134.6	SC*	2.50	124.9	SC*	6.11
2005-2009	50.4	71.0	L2*	4.55	112.3	O3*	3.12	66.3	S2*	3.60
2006-2010	53.0	71.4	L2*	5.98	99.8	O3*	3.45	65.6	R3*	3.34
2007-2011	34.3	51.3	O2	20.41	108.1	O3*	3.03	60.1	S2*	2.68
2008-2012	20.2	26.8	O3	43.27	84.1	O3*	2.89	57.4	L2*	3.31
2009-2013	6.9	18.7	O3	50.59	66.8	O3*	4.07	53.7	L3*	4.61

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONO 115kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1939-1982
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1980-2013	18.2	55.7	L3 *	4.09	55.5	L3 *	4.00	74.2	O4 *	13.60
1982-2013	17.9	55.3	L3 *	3.78	55.4	L3 *	3.85	69.7	O4 *	17.10
1984-2013	17.5	54.7	L3 *	3.55	55.5	L3 *	3.72	63.8	O4 *	21.52
1986-2013	17.0	53.7	L3 *	3.52	58.4	L2 *	3.68	57.3	O4 *	26.06
1988-2013	16.6	52.8	L3 *	3.75	64.3	L2 *	3.78	49.6	O4 *	31.63
1990-2013	15.8	51.5	S1.5 *	4.13	69.5	O3 *	3.74	43.6	O4 *	35.37
1992-2013	14.9	49.8	L2 *	5.19	72.2	O3 *	3.82	38.0	O4 *	38.87
1994-2013	14.9	49.4	L2 *	5.64	74.5	O3 *	3.94	30.4	O4 *	45.26
1996-2013	15.1	50.5	L2 *	3.94	81.1	O3 *	6.60	45.7	O4 *	30.40
1998-2013	14.3	51.0	L1.5 *	6.96	86.5	O3 *	14.63	47.0	O4 *	25.30
2000-2013	20.7	51.3	L1 *	12.66	94.3	O3 *	3.61	96.2	O3 *	3.70
2002-2013	19.8	49.8	L1	15.30	94.8	O3 *	3.98	95.1	O3 *	3.98
2004-2013	16.9	41.5	O2	24.25	90.8	O3 *	3.94	89.7	O3 *	3.90
2006-2013	14.7	34.1	O2	33.03	84.1	O3 *	3.82	67.0	L0.5 *	3.95
2008-2013	9.7	20.7	O3	47.80	70.8	O3 *	3.26	54.6	L3 *	3.61
2010-2013	2.8	11.8	O3 *	55.76	60.1	L2 *	5.10	49.5	L4 *	4.98
2012-2013	0.3	4.9	O4	63.93	45.9	L5 *	5.42	44.0	L5 *	5.60

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONO 115kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1939-1982
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1980-1981	98.9	154.9	R1.5 *	0.60	189.2	R5 *	0.66	195.1	SQ *	0.72
1980-1983	99.4	177.2	R3 *	0.31	196.6	S6 *	0.38	197.0	SQ *	0.38
1980-1985	99.5	186.0	R4 *	0.19	197.5	S6 *	0.24	197.6	S6 *	0.22
1980-1987	94.8	135.1	S0.5 *	0.60	184.2	R4 *	0.71	191.1	R5 *	0.69
1980-1989	92.8	116.5	L1.5 *	0.80	145.0	SC *	0.81	184.5	R4 *	0.56
1980-1991	86.7	97.0	L1.5 *	0.97	82.1	S1.5 *	0.94	79.9	S1.5 *	0.96
1980-1993	63.2	69.8	L2 *	2.40	57.0	R3 *	3.85	55.8	R4 *	2.16
1980-1995	0.0	58.0	L3 *	8.29	45.3	R2 *	13.14	49.4	R4 *	4.92
1980-1997	17.3	53.9	L3 *	7.19	42.5	R1.5 *	15.28	49.2	R4 *	2.40
1980-1999	13.2	52.6	L3 *	7.54	41.6	R1 *	15.88	49.0	R4 *	2.36
1980-2001	18.3	53.4	L3 *	6.24	45.2	R2 *	10.80	50.7	R4 *	1.85
1980-2003	29.5	54.3	L3 *	4.38	49.4	R2.5 *	6.11	50.0	R3 *	5.16
1980-2005	38.9	55.5	L3 *	4.39	53.7	S3 *	4.43	58.9	L2 *	9.96
1980-2007	41.7	57.0	L3 *	4.71	56.0	S2 *	4.82	81.1	O4 *	12.71
1980-2009	31.8	57.4	L3 *	3.85	56.5	S2 *	3.80	81.9	O4 *	11.13
1980-2011	27.4	57.9	L3 *	3.71	57.4	L3 *	3.66	84.8	O4 *	11.36
1980-2013	18.2	55.7	L3 *	4.09	55.5	L3 *	4.00	74.2	O4 *	13.60

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONO 115kV Conventional Oil Breakers

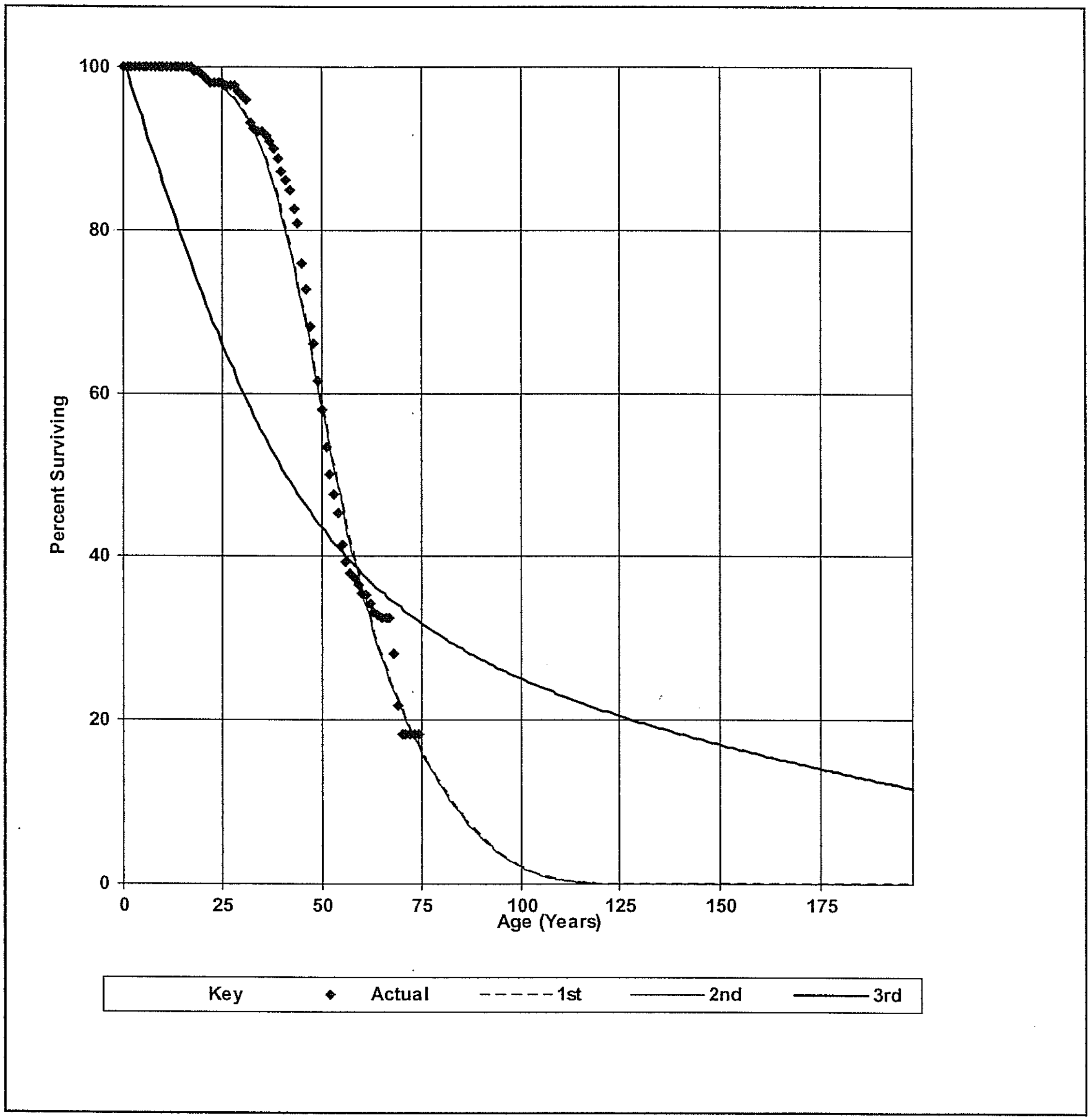
T-Cut: None

Placement Band: 1939-1982 Observation Band: 1980-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 55.7-L3 2nd: 55.5-L3 3rd: 74.2-O4

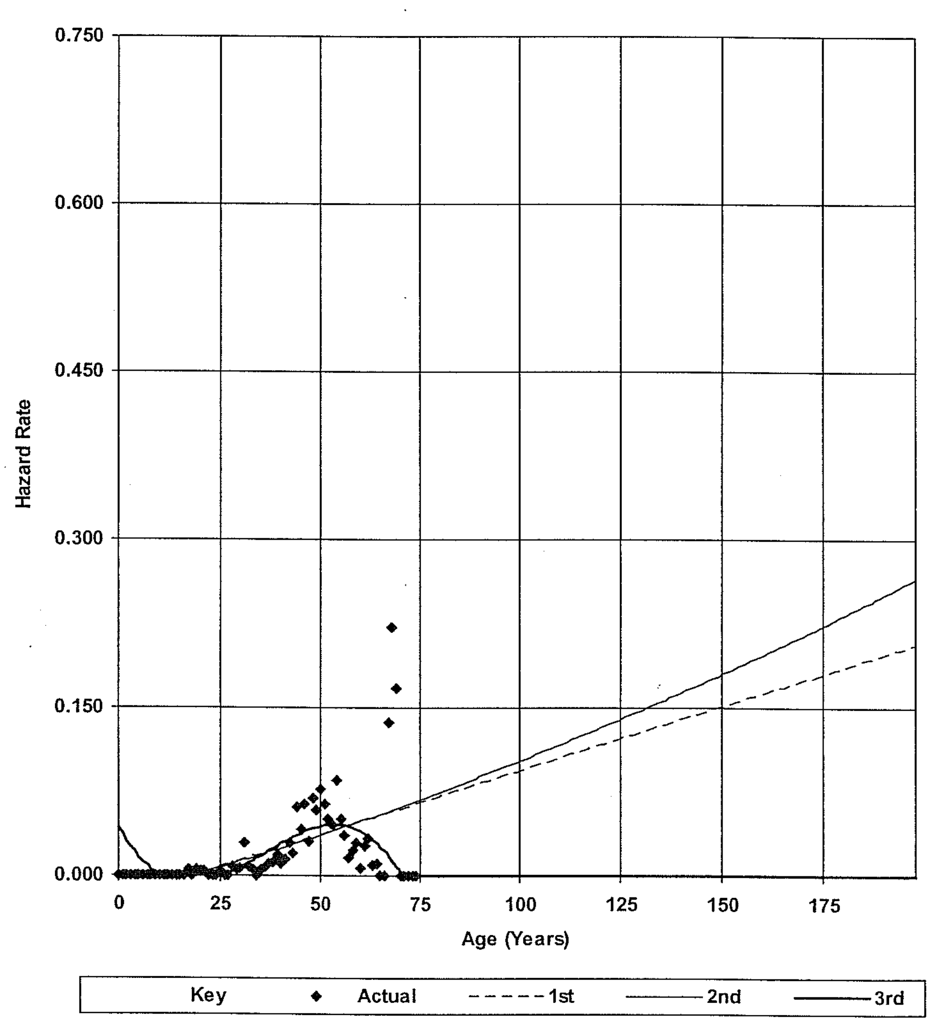


Schedule D

HYDRO ONE NETWORKS INC.
Transmission Stations
Account: 115CONO 115kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1939-1982 Observation Band: 1980-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Function
1st: 55.7-L3 2nd: 55.5-L3 3rd: 74.2-O4



Schedule E

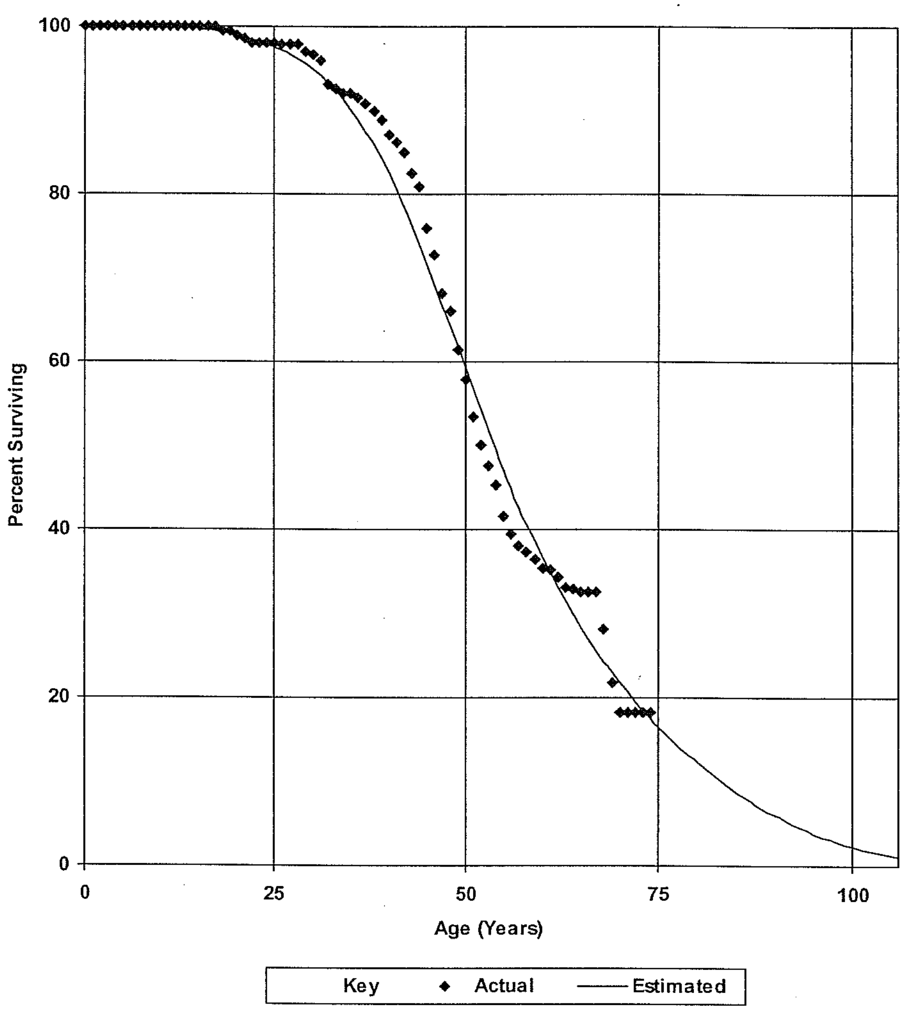
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONO 115kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1939-1982
Observation Band: 1980-2013
56.0-L3

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONS 115kV Conventional SF6 Breakers

Placement Band: 1978 - 2013
Observation Band: 1988 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	457	3	0.00656	0.99344	1.00000
0.5	407	2	0.00491	0.99509	0.99344
1.5	336	0	0.00000	1.00000	0.98855
2.5	223	0	0.00000	1.00000	0.98855
3.5	174	0	0.00000	1.00000	0.98855
4.5	150	0	0.00000	1.00000	0.98855
5.5	132	1	0.00758	0.99242	0.98855
6.5	125	5	0.04000	0.96000	0.98106
7.5	98	1	0.01020	0.98980	0.94182
8.5	107	3	0.02804	0.97196	0.93221
9.5	103	3	0.02913	0.97087	0.90607
10.5	94	1	0.01064	0.98936	0.87968
11.5	93	1	0.01075	0.98925	0.87033
12.5	92	1	0.01087	0.98913	0.86097
13.5	91	0	0.00000	1.00000	0.85161
14.5	91	0	0.00000	1.00000	0.85161
15.5	88	0	0.00000	1.00000	0.85161
16.5	83	3	0.03614	0.96386	0.85161
17.5	79	1	0.01266	0.98734	0.82083
18.5	78	0	0.00000	1.00000	0.81044
19.5	78	2	0.02564	0.97436	0.81044
20.5	76	1	0.01316	0.98684	0.78966
21.5	75	8	0.10667	0.89333	0.77927
22.5	38	4	0.10526	0.89474	0.69615
23.5	31	3	0.09677	0.90323	0.62287
24.5	28	3	0.10714	0.89286	0.56259
25.5	24	3	0.12500	0.87500	0.50231
26.5	21	1	0.04762	0.95238	0.43952
27.5	20	0	0.00000	1.00000	0.41859
28.5	20	3	0.15000	0.85000	0.41859
29.5	17	3	0.17647	0.82353	0.35580
30.5	14	5	0.35714	0.64286	0.29302
31.5	8	4	0.50000	0.50000	0.18837
32.5	4	1	0.25000	0.75000	0.09418
33.5	3	2	0.66667	0.33333	0.07064
34.5	0	0	0.00000	1.00000	0.02355

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONS 115kV Conventional SF6 Breakers

T-Cut: None

Placement Band: 1978-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-1992	88.1	40.6	L0.5	2.72	171.2	R2 *	2.63	172.8	R2 *	1.90
1989-1993	100.0				No Retirements					
1990-1994	100.0				No Retirements					
1991-1995	100.0				No Retirements					
1992-1996	100.0				No Retirements					
1993-1997	100.0				No Retirements					
1994-1998	95.2	175.9	R2.5 *	4.49	175.6	R2.5 *	4.64	27.6	R4 *	3.84
1995-1999	86.6	58.4	O2	6.14	154.2	R0.5 *	5.57	23.7	R4 *	2.72
1996-2000	86.4	128.3	SC *	6.65	149.2	SC *	6.09	25.4	R4 *	2.62
1997-2001	82.9	130.1	SC *	12.08	146.0	SC *	8.51	25.7	R2 *	6.09
1998-2002	76.6	119.2	SC *	14.14	133.2	SC *	8.48	25.7	R1 *	6.10
1999-2003	78.7	45.8	O2	11.17	131.6	SC *	8.96	25.9	R2.5 *	6.40
2000-2004	66.0	32.2	L0.5	7.65	32.5	L0.5	7.45	24.9	R2 *	6.23
2001-2005	61.2	29.4	L1	7.46	27.7	S0	8.50	24.8	R1.5 *	7.77
2002-2006	63.6	33.3	L2 *	3.13	32.0	S1 *	3.04	118.3	SC *	2.95
2003-2007	60.2	36.6	L2 *	5.51	34.4	S1.5 *	5.51	132.7	SC *	4.20
2004-2008	60.0	37.8	L2 *	5.40	34.6	S1.5 *	4.98	123.9	SC *	4.39
2005-2009	63.5	42.8	L2 *	4.91	36.3	S3 *	4.48	35.5	S3 *	4.72
2006-2010	50.6	35.0	L2 *	6.93	32.7	S3 *	3.32	30.1	R3 *	5.85
2007-2011	16.2	25.4	L2 *	14.34	27.7	L4 *	4.70	26.4	R3 *	7.14
2008-2012	0.0	21.1	L2 *	9.86	25.7	R4 *	15.33	24.1	R2.5 *	10.41
2009-2013	0.1	17.8	L2 *	9.02	23.3	S3 *	25.92	22.4	R2.5	22.86

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONS 115kV Conventional SF6 Breakers

T-Cut: None

Placement Band: 1978-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-2013	2.4	24.4	L2 *	9.19	25.1	R3 *	5.37	24.4	R2.5 *	3.02
1990-2013	2.4	24.5	L2 *	9.19	25.2	R3 *	5.32	24.6	R2.5 *	3.06
1992-2013	2.3	24.4	L2 *	9.00	25.2	R3 *	5.62	24.5	R2.5 *	3.07
1994-2013	2.3	24.2	L2 *	8.82	25.1	R3 *	5.77	24.3	R2.5 *	3.05
1996-2013	2.3	24.0	L2 *	8.85	25.1	R3 *	6.03	24.0	R2.5 *	2.98
1998-2013	2.2	23.5	L2 *	8.59	25.0	R3 *	6.87	23.5	R2 *	2.94
2000-2013	2.3	23.4	L2 *	9.41	25.3	S3 *	6.51	23.8	R2.5 *	3.08
2002-2013	2.1	22.8	L2 *	9.04	25.4	S3 *	8.28	23.9	R2.5 *	3.72
2004-2013	2.0	21.9	L2 *	10.56	25.3	S3 *	8.01	24.0	R2.5 *	4.20
2006-2013	1.6	21.3	L2 *	12.02	25.3	R4 *	8.41	24.1	R2.5 *	5.15
2008-2013	0.9	19.1	L2 *	12.38	24.2	R4 *	12.51	23.2	R2.5	9.02
2010-2013	0.0	16.5	L2 *	8.53	22.4	S3 *	23.36	21.7	R3	20.85
2012-2013	0.0	14.6	L2 *	26.84	20.7	S3 *	14.02	20.0	R2.5	11.90

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONS 115kV Conventional SF6 Breakers

T-Cut: None

Placement Band: 1978-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-1989	85.6	19.5	L1	5.13	145.1	SC *	9.83	155.4	R0.5 *	5.23
1988-1991	88.1	35.7	L0.5	2.91	166.7	R1 *	3.87	168.9	R1.5 *	2.70
1988-1993	89.3	48.0	L0.5	2.85	175.9	R2.5 *	1.74	176.3	R2.5 *	1.57
1988-1995	92.4	67.9	L0.5	2.04	183.3	R4 *	0.99	183.3	R4 *	0.99
1988-1997	93.9	101.5	L0.5	1.77	187.9	R5 *	1.07	51.7	R5 *	1.04
1988-1999	85.1	51.3	L0.5	2.89	169.2	R1.5 *	2.69	24.3	R4 *	2.20
1988-2001	84.3	55.9	L0	3.25	166.2	R1 *	2.78	27.9	R3 *	2.45
1988-2003	77.9	47.7	L0	3.37	156.1	R0.5 *	2.87	27.1	R3 *	2.29
1988-2005	62.1	34.9	L1	2.88	31.2	S0.5	2.83	26.4	R2.5 *	2.18
1988-2007	66.1	40.5	L1	2.44	48.8	O2 *	2.47	30.8	R2 *	2.47
1988-2009	56.3	39.3	L1	2.59	34.8	S0.5	2.34	29.9	R2.5 *	2.16
1988-2011	17.5	29.1	L2 *	6.88	27.5	R3 *	5.38	26.2	R2.5 *	3.78
1988-2013	2.4	24.4	L2 *	9.19	25.1	R3 *	5.37	24.4	R2.5 *	3.02

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONS 115kV Conventional SF6 Breakers

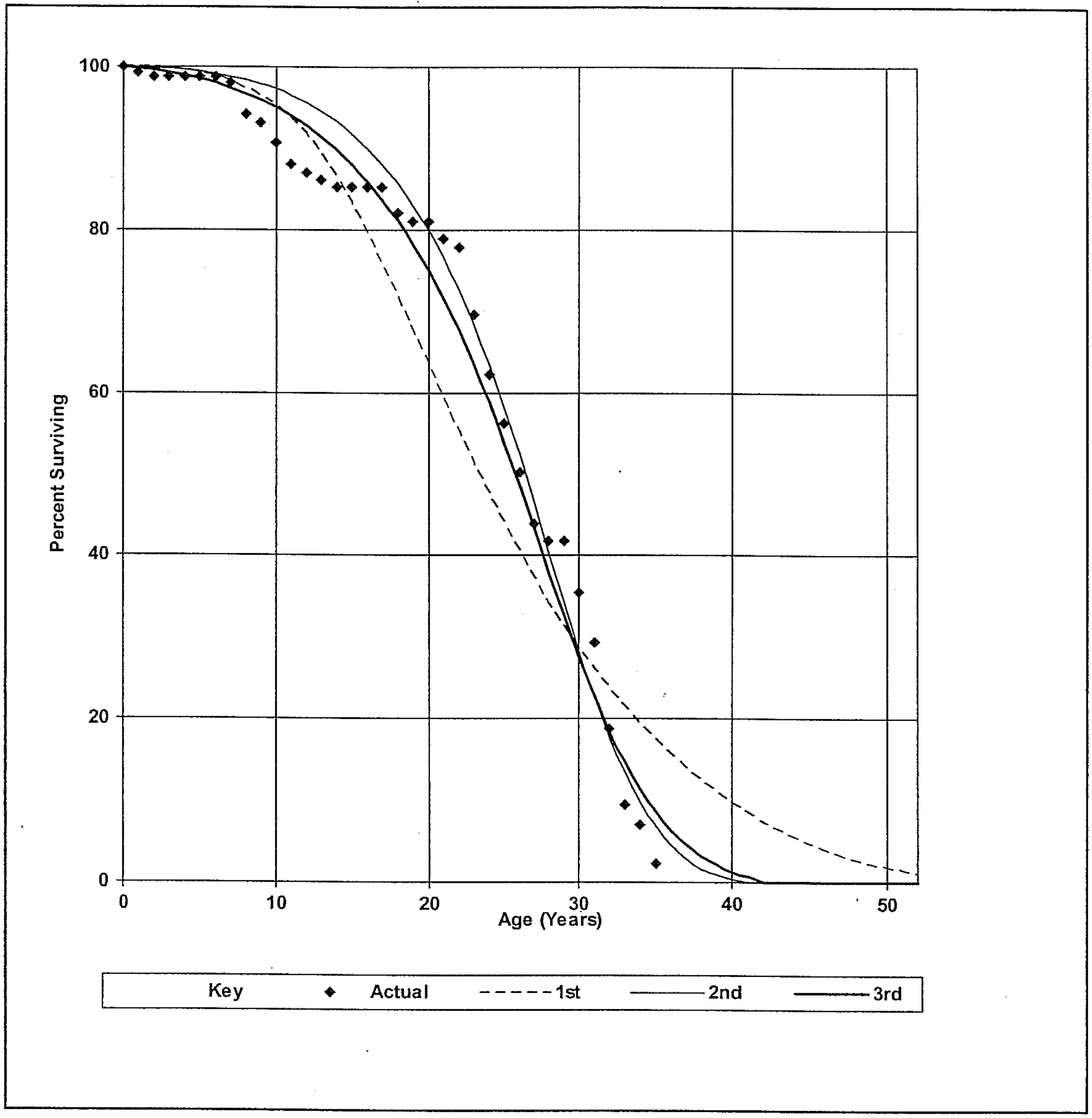
T-Cut: None

Placement Band: 1978-2013 Observation Band: 1988-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 24.4-L2 2nd: 25.1-R3 3rd: 24.4-R2.5



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONS 115kV Conventional SF6 Breakers

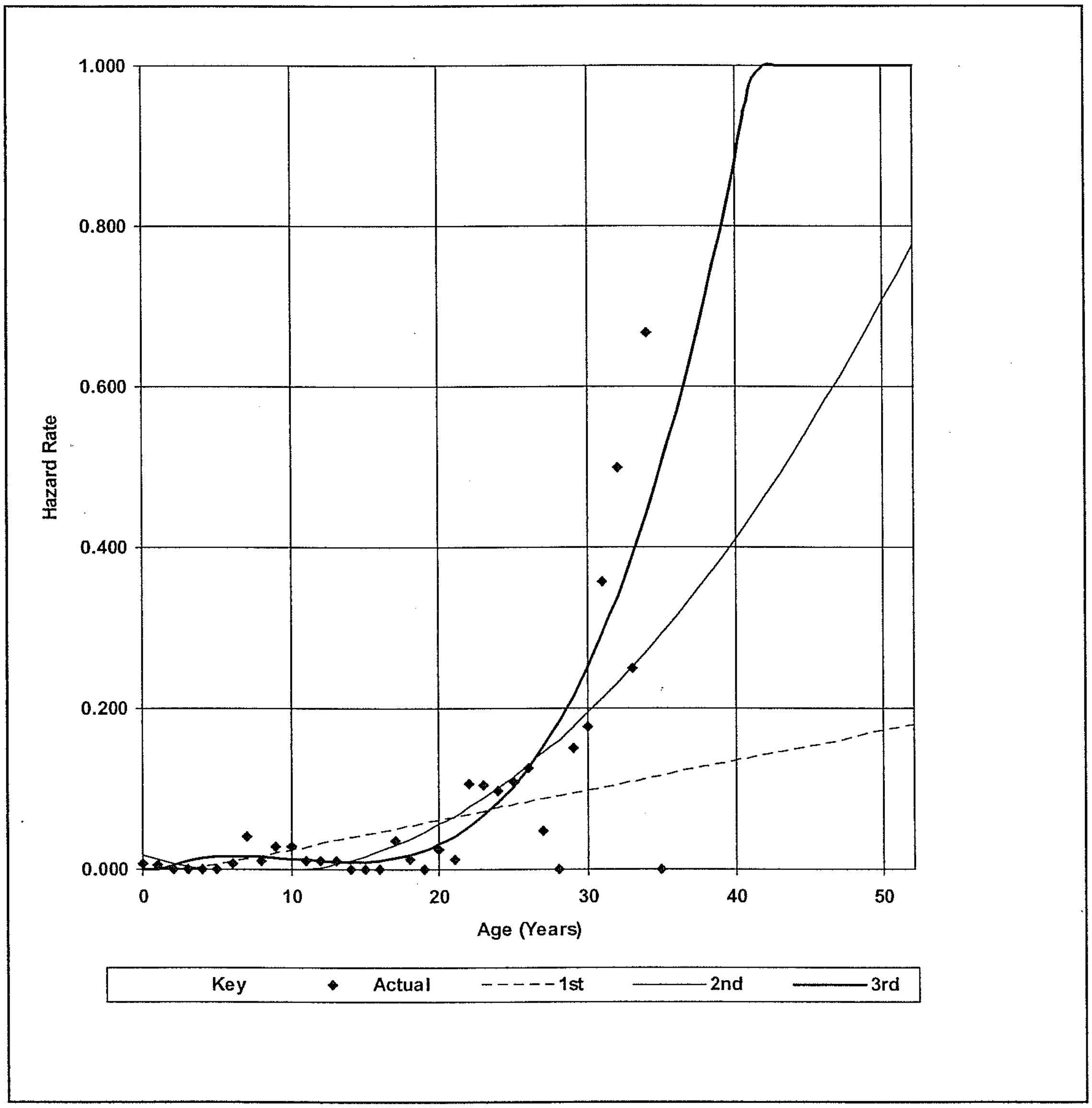
T-Cut: None

Placement Band: 1978-2013 Observation Band: 1988-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function 1st: 24.4-L2 2nd: 25.1-R3 3rd: 24.4-R2.5



Schedule E

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 115CONS 115kV Conventional SF6 Breakers

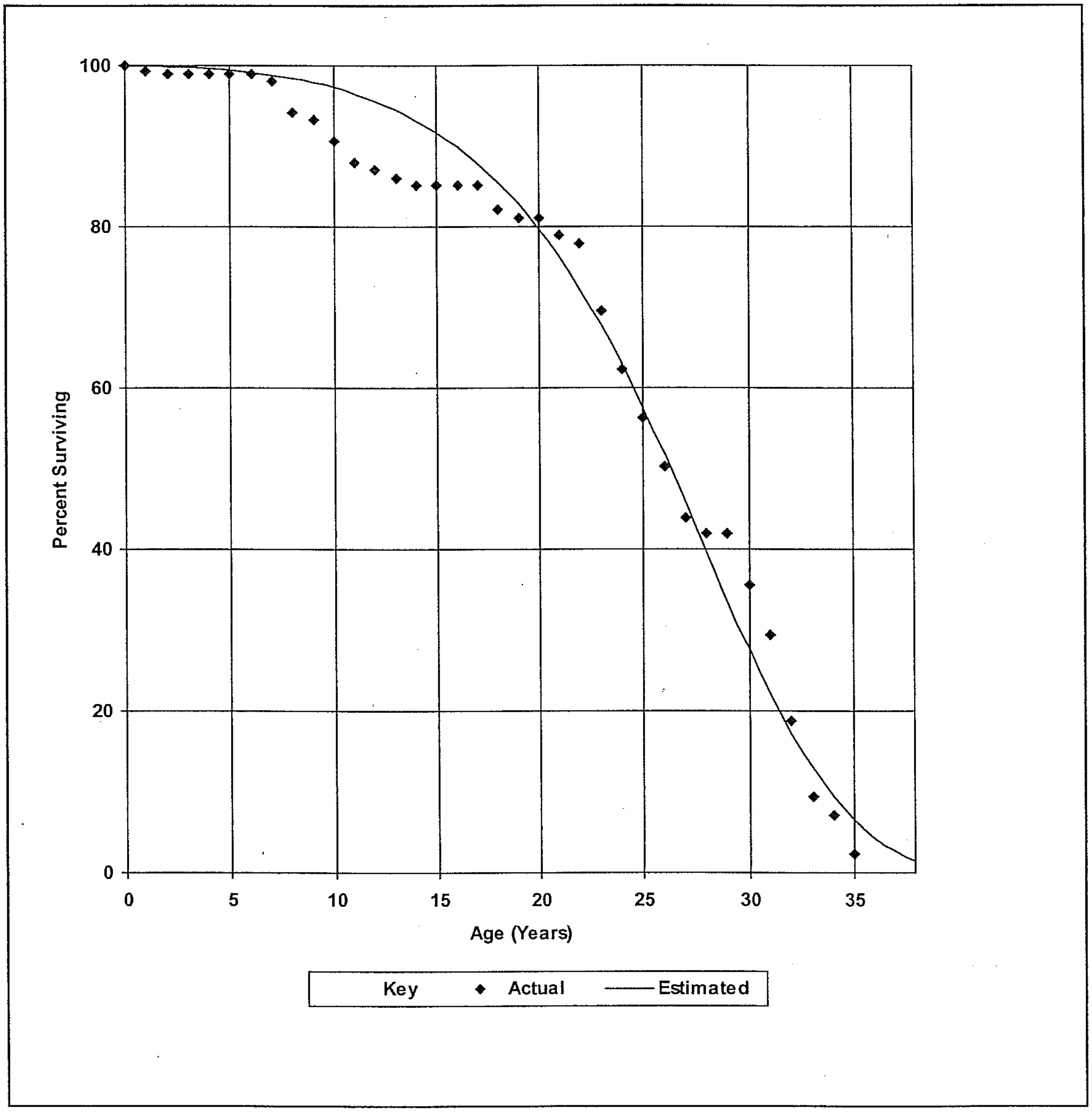
T-Cut: None

Placement Band: 1978-2013

Observation Band: 1988-2013

Estimated Projection Life Curve

25.0-R3



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230BRKX 230kV Breakers

Placement Band: 1947 - 2012
Observation Band: 1975 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	360	0	0.00000	1.00000	1.00000
0.5	401	0	0.00000	1.00000	1.00000
1.5	400	9	0.02250	0.97750	1.00000
2.5	386	2	0.00518	0.99482	0.97750
3.5	372	0	0.00000	1.00000	0.97244
4.5	414	6	0.01449	0.98551	0.97244
5.5	444	1	0.00225	0.99775	0.95834
6.5	397	3	0.00756	0.99244	0.95618
7.5	388	4	0.01031	0.98969	0.94896
8.5	409	2	0.00489	0.99511	0.93917
9.5	421	6	0.01425	0.98575	0.93458
10.5	415	0	0.00000	1.00000	0.92126
11.5	447	5	0.01119	0.98881	0.92126
12.5	527	8	0.01518	0.98482	0.91096
13.5	518	3	0.00579	0.99421	0.89713
14.5	537	4	0.00745	0.99255	0.89193
15.5	594	0	0.00000	1.00000	0.88529
16.5	618	16	0.02589	0.97411	0.88529
17.5	611	4	0.00655	0.99345	0.86237
18.5	617	5	0.00810	0.99190	0.85672
19.5	616	7	0.01136	0.98864	0.84978
20.5	612	4	0.00654	0.99346	0.84012
21.5	593	3	0.00506	0.99494	0.83463
22.5	588	1	0.00170	0.99830	0.83041
23.5	586	3	0.00512	0.99488	0.82900
24.5	597	4	0.00670	0.99330	0.82476
25.5	560	3	0.00536	0.99464	0.81923
26.5	573	2	0.00349	0.99651	0.81484
27.5	577	21	0.03640	0.96360	0.81200
28.5	556	6	0.01079	0.98921	0.78244
29.5	550	6	0.01091	0.98909	0.77400
30.5	537	1	0.00186	0.99814	0.76556
31.5	521	5	0.00960	0.99040	0.76413
32.5	508	8	0.01575	0.98425	0.75680
33.5	486	6	0.01235	0.98765	0.74488
34.5	482	10	0.02075	0.97925	0.73568
35.5	464	10	0.02155	0.97845	0.72042

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230BRKX 230kV Breakers

Placement Band: 1947 - 2012
Observation Band: 1975 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	400	11	0.02750	0.97250	0.70489
37.5	368	2	0.00543	0.99457	0.68551
38.5	355	12	0.03380	0.96620	0.68178
39.5	343	9	0.02624	0.97376	0.65874
40.5	312	7	0.02244	0.97756	0.64145
41.5	281	15	0.05338	0.94662	0.62706
42.5	251	32	0.12749	0.87251	0.59359
43.5	189	16	0.08466	0.91534	0.51791
44.5	131	6	0.04580	0.95420	0.47407
45.5	107	5	0.04673	0.95327	0.45235
46.5	101	8	0.07921	0.92079	0.43122
47.5	75	19	0.25333	0.74667	0.39706
48.5	54	11	0.20370	0.79630	0.29647
49.5	43	4	0.09302	0.90698	0.23608
50.5	37	5	0.13514	0.86486	0.21412
51.5	32	7	0.21875	0.78125	0.18518
52.5	17	0	0.00000	1.00000	0.14467
53.5	15	1	0.06667	0.93333	0.14467
54.5	14	3	0.21429	0.78571	0.13503
55.5	11	0	0.00000	1.00000	0.10609
56.5	11	0	0.00000	1.00000	0.10609
57.5	10	0	0.00000	1.00000	0.10609
58.5	10	2	0.20000	0.80000	0.10609
59.5	8	0	0.00000	1.00000	0.08488
60.5	7	1	0.14286	0.85714	0.08488
61.5	6	0	0.00000	1.00000	0.07275
62.5	6	0	0.00000	1.00000	0.07275
63.5	4	0	0.00000	1.00000	0.07275
64.5	2	1	0.50000	0.50000	0.07275
65.5	0	0	0.00000	1.00000	0.03638

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230BRKX 230kV Breakers

T-Cut: None

Placement Band: 1947-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1975-1979	87.5	161.4	R1 *	3.89	169.4	R1.5 *	2.04	37.3	R3 *	1.67
1976-1980	87.8	164.4	R1 *	4.06	169.2	R1.5 *	2.20	33.3	R3 *	1.53
1977-1981	86.5	161.3	R1 *	4.90	164.2	R1 *	3.45	30.7	R3 *	1.57
1978-1982	90.3	175.6	R2.5 *	1.96	115.7	R3 *	1.70	38.3	R3 *	1.37
1979-1983	88.4	173.0	R2 *	2.71	50.5	R1.5	3.20	33.4	R3 *	2.64
1980-1984	96.6	90.3	L1.5 *	0.69	55.0	S2 *	0.61	180.9	R3 *	0.77
1981-1985	90.0	140.0	R1	3.71	58.8	S2	3.08	48.1	R3	3.11
1982-1986	83.7	162.0	R1.5	6.48	64.0	S2	5.99	54.8	R3	6.01
1983-1987	78.1	185.6	R4 *	9.25	68.6	R2.5	8.83	73.2	S1.5	8.82
1984-1988	90.8	123.9	SC	3.17	178.4	R3 *	1.77	176.8	R2.5 *	2.04
1985-1989	92.1	122.1	SC	3.92	177.6	R2.5 *	2.25	175.4	R2 *	2.90
1986-1990	91.4	141.7	SC	2.53	180.5	R3 *	1.06	180.3	R3 *	1.13
1987-1991	80.9	92.3	L0.5	2.06	166.6	R1 *	1.74	165.5	R1 *	1.37
1988-1992	72.5	75.1	L1 *	1.87	67.4	S0.5	1.81	56.8	R2.5 *	2.06
1989-1993	68.3	88.5	L0	2.53	55.1	R1	2.62	47.8	R2.5	2.72
1990-1994	60.0	68.5	L0.5	4.32	49.5	R1.5	2.98	46.0	R2	3.24
1991-1995	53.1	56.5	L1.5 *	3.40	44.6	R1	5.17	43.1	R2 *	3.11
1992-1996	41.7	49.5	L2 *	6.79	39.9	R1.5	10.24	40.1	R2 *	6.42
1993-1997	31.2	46.2	L2 *	8.27	37.5	R1	12.00	38.1	R1.5 *	8.04
1994-1998	23.2	44.5	L3 *	10.41	39.0	R2 *	12.70	39.5	R2 *	9.88
1995-1999	0.0	44.3	L3 *	12.80	37.1	R1.5 *	16.85	38.3	R2 *	13.02
1996-2000	6.5	43.1	L3 *	11.96	36.2	R1.5 *	16.72	38.6	R2 *	11.56
1997-2001	3.5	40.3	L3 *	13.18	35.1	R2 *	15.50	39.9	R4 *	7.03
1998-2002	2.4	41.0	L3 *	13.90	35.6	R2 *	15.60	41.5	S4 *	6.58
1999-2003	2.1	42.3	L3 *	12.88	37.0	R2.5 *	12.28	41.5	R4 *	7.18
2000-2004	5.2	43.4	L3 *	11.85	39.0	R3 *	9.85	40.7	R4 *	7.53
2001-2005	10.5	45.7	L3 *	10.24	42.2	R3 *	6.11	41.7	R3 *	6.36
2002-2006	29.1	59.5	L2 *	11.25	50.0	R2.5	7.41	50.8	R2	7.64
2003-2007	23.5	54.4	L1.5 *	11.98	47.2	R1.5	9.02	79.7	O4 *	10.01
2004-2008	21.6	44.7	L1.5 *	6.02	42.5	S0.5	5.14	54.7	L1.5 *	5.87
2005-2009	7.5	31.5	O2	4.91	30.1	O2	5.05	29.6	O2	5.42
2006-2010	3.6	31.2	L0	6.56	30.3	SC	7.56	29.5	SC	6.47
2007-2011	3.7	30.2	L0	6.81	29.9	SC	8.00	28.7	L0	6.08
2008-2012	2.1	31.3	L0	5.94	31.3	SC	7.41	28.7	L0	4.21
2009-2013	0.8	33.2	O2	7.31	33.0	SC	9.30	30.2	SC	5.33

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230BRKX 230kV Breakers

T-Cut: None

Placement Band: 1947-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1975-2013	3.6	45.2	L2*	8.70	40.2	R1.5	3.81	40.3	R2	3.20
1977-2013	3.6	45.2	L2*	8.80	39.9	R1.5	3.81	40.0	R2	3.19
1979-2013	3.6	45.3	L2*	8.71	40.0	R1.5	3.86	40.1	R2	3.24
1981-2013	3.7	45.4	L2*	8.55	40.3	R2	3.90	40.4	R2	3.29
1983-2013	3.6	45.3	L2*	8.63	40.1	R1.5	3.88	40.1	R2	3.27
1985-2013	3.6	45.3	L2*	8.76	39.9	R1.5	3.88	39.8	R1.5	3.25
1987-2013	3.6	45.1	L2*	8.74	39.8	R1.5	3.93	39.7	R1.5	3.27
1989-2013	3.5	44.9	L2*	8.84	39.8	R1.5	3.96	39.6	R1.5	3.27
1991-2013	3.3	44.1	L2*	8.79	39.2	R1.5	4.08	38.9	R1.5	3.32
1993-2013	3.2	43.5	L2*	8.84	38.8	R1.5	4.38	38.5	R1.5	3.52
1995-2013	3.1	43.1	L2*	8.73	39.0	R1.5	4.97	38.6	R1.5	4.05
1997-2013	3.1	43.0	L2*	8.87	39.3	R1.5	5.28	38.9	R1.5	4.54
1999-2013	3.1	42.3	L2*	9.10	38.7	R1.5	6.05	38.4	R1.5	5.48
2001-2013	3.5	40.9	L1.5*	8.63	37.7	R1	6.59	37.5	R1	6.26
2003-2013	4.3	39.7	L0.5	6.43	37.0	R0.5	5.48	36.0	R0.5	4.10
2005-2013	3.1	36.2	L0	5.11	34.8	SC	4.91	33.4	SC	3.22
2007-2013	1.9	33.0	L0	5.82	32.6	SC	7.09	30.9	SC	4.39
2009-2013	0.8	33.2	O2	7.31	33.0	SC	9.30	30.2	SC	5.33
2011-2013	1.6	43.1	L0.5	9.59	42.0	R1	10.88	38.5	R0.5	5.97
2013-2013	18.1	40.0	L0	7.34	38.8	R0.5	10.08	37.4	SC	9.75

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230BRKX 230kV Breakers

T-Cut: None

Placement Band: 1947-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1975-1976	98.8	192.3	SQ*	1.75	192.9	S6*	1.40	30.6	S4*	0.88
1975-1978	94.7	174.9	R2.5*	4.38	180.8	R3*	2.56	30.0	R4*	1.54
1975-1980	89.5	167.8	R1.5*	3.82	172.7	R2*	2.06	34.1	R3*	1.15
1975-1982	91.1	174.2	R2*	3.14	176.7	R2.5*	1.92	34.5	R4*	0.81
1975-1984	89.1	176.2	R2.5*	2.36	177.5	R2.5*	1.91	35.4	R4*	0.98
1975-1986	88.9	177.5	R2.5*	1.95	178.4	R3*	1.62	38.1	R4*	1.04
1975-1988	87.0	169.0	R1.5*	1.76	171.9	R2*	1.22	171.9	R2*	1.21
1975-1990	88.1	173.4	R2*	1.55	174.5	R2*	1.20	81.4	R2.5	1.07
1975-1992	71.6	96.0	L0	2.40	59.1	R1.5	1.92	53.3	R2.5	2.21
1975-1994	64.8	82.1	L0	2.10	54.1	R1.5	2.10	48.8	R2.5	2.13
1975-1996	43.7	58.3	L1.5*	4.90	45.1	R1.5	5.77	44.3	R3*	3.00
1975-1998	26.0	52.4	L2*	7.87	41.9	R2	8.25	42.8	R3*	3.93
1975-2000	7.8	49.6	L2*	9.36	40.4	R2*	9.57	41.9	R3*	4.48
1975-2002	7.7	45.4	L2*	10.04	38.4	R2*	9.16	40.9	R3*	3.14
1975-2004	9.1	47.1	L2*	10.42	39.6	R2*	7.83	41.8	R3*	2.85
1975-2006	12.4	48.6	L2*	10.37	41.1	R2*	6.19	42.5	R3*	3.24
1975-2008	11.0	46.4	L2*	9.39	41.2	R2.5*	5.00	41.7	R2.5	3.82
1975-2010	7.1	44.9	L2*	9.17	39.5	R2	4.36	39.8	R2	3.49
1975-2012	6.3	45.1	L2*	9.04	40.1	R2	4.12	40.3	R2	3.35
1975-2013	3.6	45.2	L2*	8.70	40.2	R1.5	3.81	40.3	R2	3.20

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230BRKX 230kV Breakers

T-Cut: None

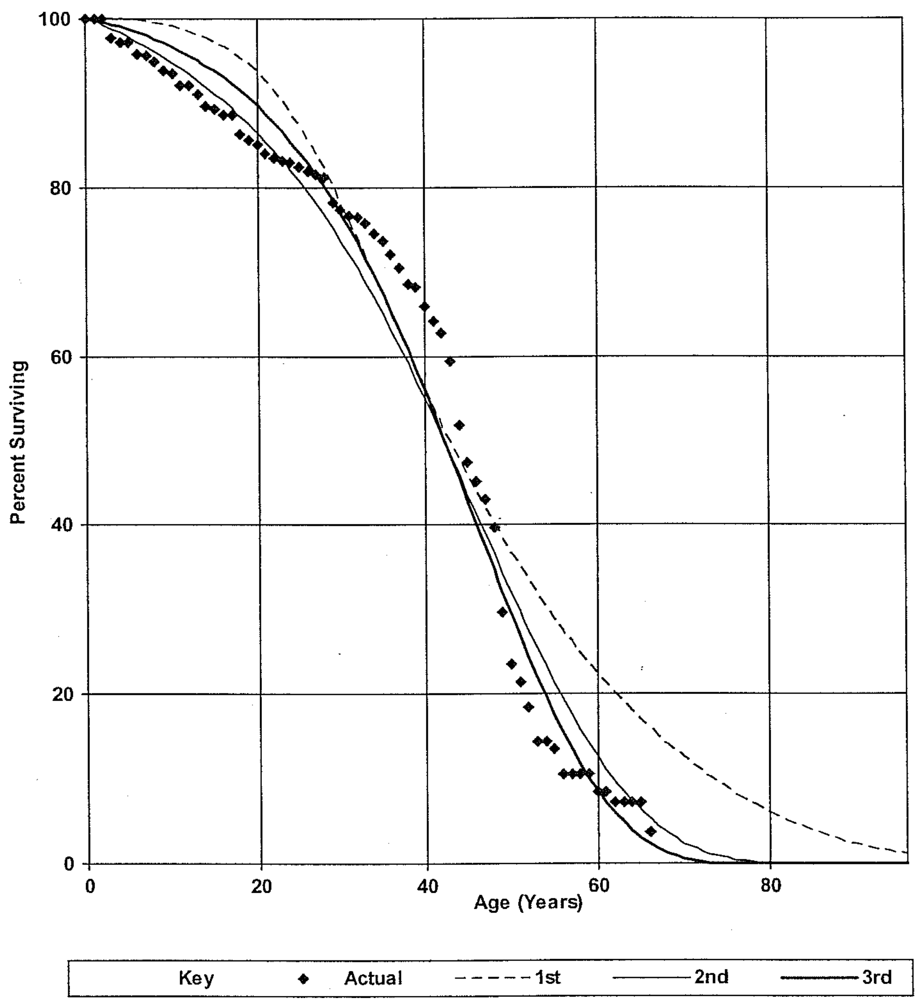
Placement Band: 1947-2012 Observation Band: 1975-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 45.2-L2 2nd: 40.2-R1.5 3rd: 40.3-R2



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Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230BRKX 230kV Breakers

T-Cut: None

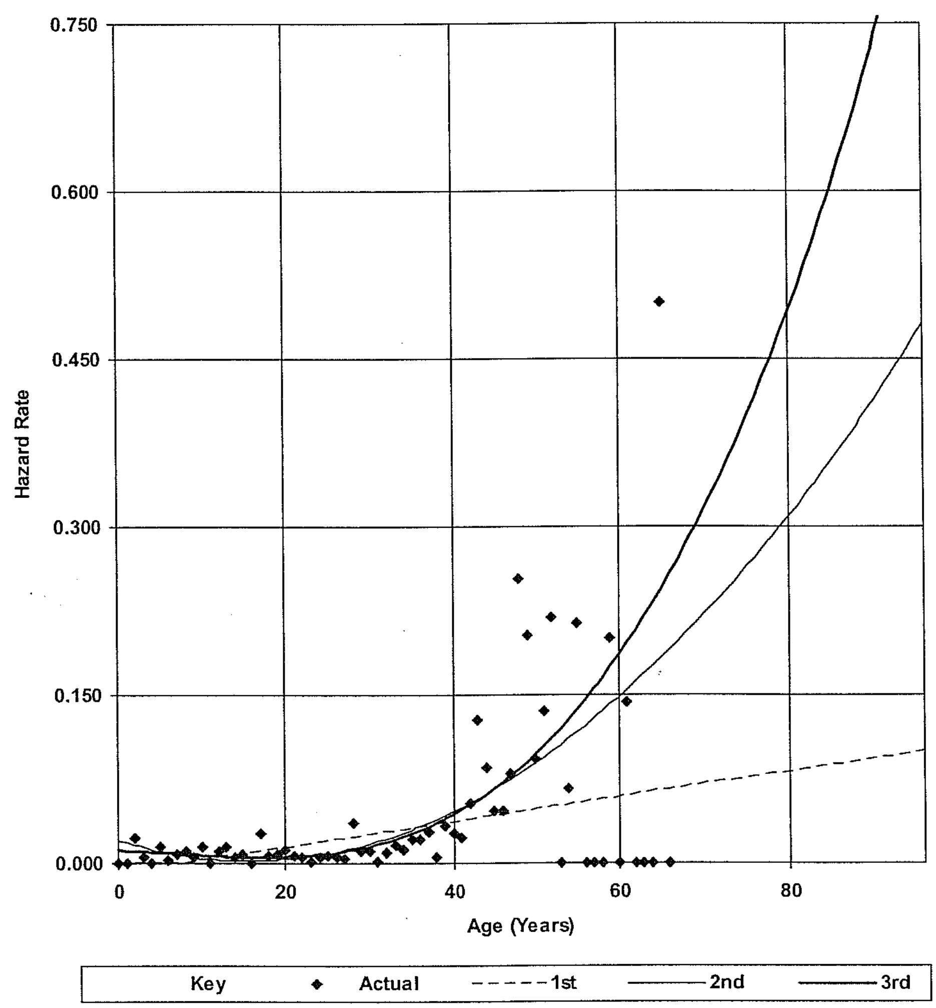
Placement Band: 1947-2013 Observation Band: 1975-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 45.2-L2 2nd: 40.2-R1.5 3rd: 40.3-R2



Schedule E

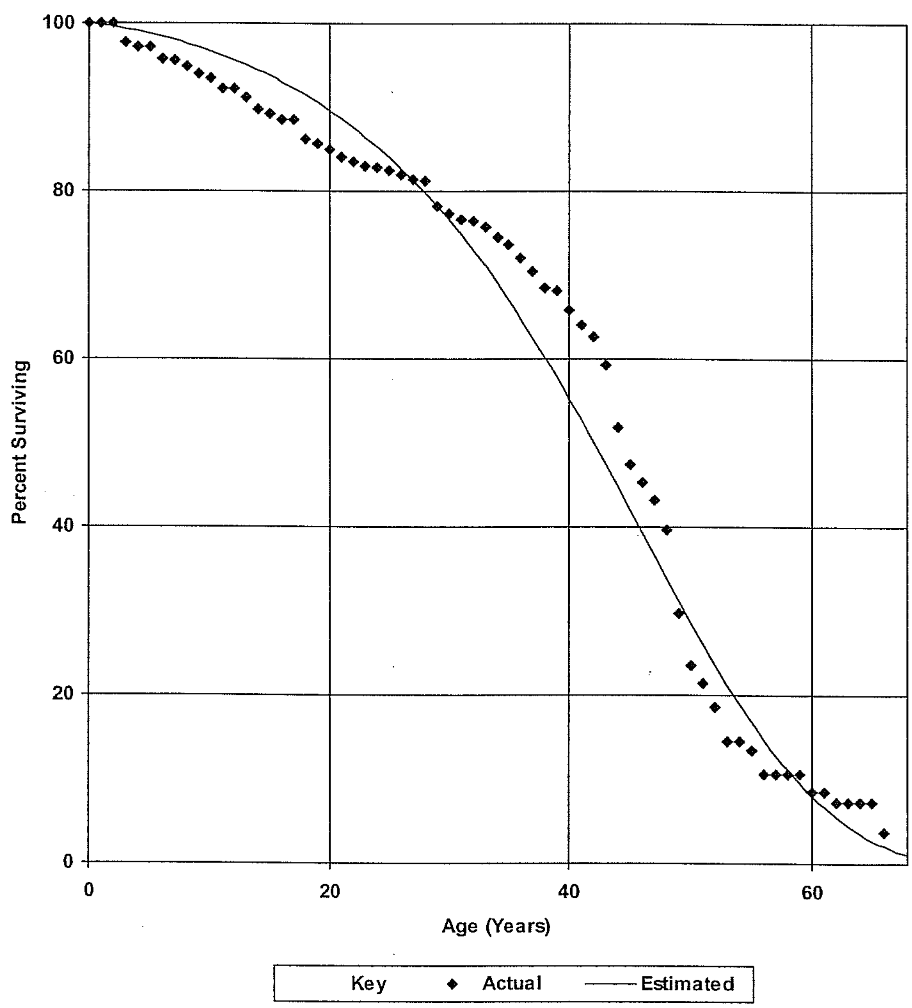
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230BRKX 230kV Breakers

T-Cut: None
Placement Band: 1947-2012
Observation Band: 1975-2013
40.0-R2

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONA 230kV Conventional Air Breakers

Placement Band: 1957 - 1982
Observation Band: 1975 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	15	0	0.00000	1.00000	1.00000
0.5	26	0	0.00000	1.00000	1.00000
1.5	37	0	0.00000	1.00000	1.00000
2.5	57	0	0.00000	1.00000	1.00000
3.5	58	0	0.00000	1.00000	1.00000
4.5	98	0	0.00000	1.00000	1.00000
5.5	144	1	0.00694	0.99306	1.00000
6.5	168	0	0.00000	1.00000	0.99306
7.5	174	4	0.02299	0.97701	0.99306
8.5	194	2	0.01031	0.98969	0.97023
9.5	215	4	0.01860	0.98140	0.96022
10.5	211	0	0.00000	1.00000	0.94236
11.5	213	0	0.00000	1.00000	0.94236
12.5	213	0	0.00000	1.00000	0.94236
13.5	213	0	0.00000	1.00000	0.94236
14.5	217	0	0.00000	1.00000	0.94236
15.5	220	0	0.00000	1.00000	0.94236
16.5	233	0	0.00000	1.00000	0.94236
17.5	242	0	0.00000	1.00000	0.94236
18.5	242	0	0.00000	1.00000	0.94236
19.5	242	0	0.00000	1.00000	0.94236
20.5	242	0	0.00000	1.00000	0.94236
21.5	242	0	0.00000	1.00000	0.94236
22.5	242	1	0.00413	0.99587	0.94236
23.5	241	3	0.01245	0.98755	0.93847
24.5	238	1	0.00420	0.99580	0.92678
25.5	237	2	0.00844	0.99156	0.92289
26.5	235	2	0.00851	0.99149	0.91510
27.5	233	2	0.00858	0.99142	0.90731
28.5	231	0	0.00000	1.00000	0.89953
29.5	231	1	0.00433	0.99567	0.89953
30.5	230	1	0.00435	0.99565	0.89563
31.5	217	0	0.00000	1.00000	0.89174
32.5	217	4	0.01843	0.98157	0.89174
33.5	213	4	0.01878	0.98122	0.87530
34.5	209	5	0.02392	0.97608	0.85886
35.5	204	6	0.02941	0.97059	0.83832

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONA 230kV Conventional Air Breakers

Placement Band: 1957 - 1982
Observation Band: 1975 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	198	2	0.01010	0.98990	0.81366
37.5	196	0	0.00000	1.00000	0.80544
38.5	195	11	0.05641	0.94359	0.80544
39.5	174	4	0.02299	0.97701	0.76000
40.5	166	4	0.02410	0.97590	0.74253
41.5	143	14	0.09790	0.90210	0.72464
42.5	128	29	0.22656	0.77344	0.65370
43.5	75	11	0.14667	0.85333	0.50559
44.5	37	1	0.02703	0.97297	0.43144
45.5	20	0	0.00000	1.00000	0.41978
46.5	19	0	0.00000	1.00000	0.41978
47.5	2	0	0.00000	1.00000	0.41978
48.5	0	0	0.00000	1.00000	0.41978

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONA 230kV Conventional Air Breakers

T-Cut: None
Placement Band: 1957-1982
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1975-1979	91.2	156.3	R0.5 *	5.91	172.0	R2 *	3.21	31.3	R3 *	2.13
1976-1980	92.4	165.5	R1 *	7.14	174.6	R2 *	3.29	29.7	R4 *	1.93
1977-1981	91.6	162.5	R1 *	9.05	168.3	R1.5 *	6.01	29.1	R4 *	1.78
1978-1982	95.9	177.5	R2.5 *	5.99	181.1	R4 *	4.22	33.2	R5 *	1.21
1979-1983	92.0	173.3	R2 *	5.28	50.3	R1.5	6.68	33.4	R4 *	2.90
1980-1984	96.6	82.4	L2 *	0.66	54.9	S2 *	0.61	183.7	R4 *	0.99
1981-1985	95.0	89.5	L1.5 *	1.18	61.3	S2 *	1.15	190.0	R5 *	1.06
1982-1986	88.9	97.5	L1.5 *	4.21	68.9	S2 *	4.20	191.5	R5 *	3.73
1983-1987	83.3	106.3	L1.5 *	7.34	79.1	S1.5 *	7.33	192.3	SQ *	6.80
1984-1988	100.0				No Retirements					
1985-1989	100.0				No Retirements					
1986-1990	100.0				No Retirements					
1987-1991	90.9	66.6	L2 *	2.08	44.0	R3 *	7.64	40.4	R5 *	3.30
1988-1992	92.0	69.3	L2 *	1.69	46.4	R3 *	6.76	43.8	S4 *	1.83
1989-1993	92.9	72.1	L2 *	1.37	49.4	R3 *	5.62	48.2	S4 *	1.39
1990-1994	84.3	56.0	L3 *	2.28	44.1	R3 *	6.63	51.5	L2 *	11.09
1991-1995	78.7	54.6	L3 *	2.22	49.8	S2 *	2.09	106.3	O4 *	30.79
1992-1996	83.8	66.5	L2 *	2.01	157.3	R0.5 *	2.00	132.9	SC *	21.69
1993-1997	71.1	74.7	L1.5 *	6.20	171.3	R1.5 *	6.61	151.7	SC *	12.20
1994-1998	55.6	77.5	L0.5	11.86	171.4	R1.5 *	13.00	158.3	R0.5 *	12.63
1995-1999	94.3	149.8	SC *	11.89	181.6	R3 *	2.46	115.4	R4 *	2.56
1996-2000	60.4	51.7	S3 *	5.48	19.9	O4 *	56.44	42.2	R4 *	8.17
1997-2001	0.0	39.8	L5 *	13.30	1.5	O3 *	90.13	34.6	R3 *	21.30
1998-2002	0.0	39.9	L5 *	9.40	1.0	O3 *	90.01	34.5	R3 *	19.05
1999-2003	0.0	40.3	L5 *	9.14	0.7	O2 *	89.12	34.3	R3 *	17.96
2000-2004	0.0	40.8	L5 *	9.60	0.5	O3 *	91.20	33.3	R3 *	23.64
2001-2005	0.0	41.9	L5 *	13.03	0.5	R5 *	90.02	31.9	S2 *	26.45
2002-2006	72.3	61.4	L3 *	6.19	7.0	O4	77.97	42.4	R4 *	2.34
2003-2007	47.6	51.3	L4 *	8.11	1.1	O3 *	89.60	37.6	R3 *	10.59
2004-2008	14.5	46.6	S4 *	9.95	0.5	O3 *	90.04	34.9	S3 *	19.67
2005-2009	23.0	44.7	L5 *	8.26	0.4	S3 *	88.84	36.5	S3 *	14.07
2006-2010	33.9	45.2	S4 *	7.76	0.5	O3 *	87.53	36.7	R3 *	12.05
2007-2011	47.4	45.7	L5 *	2.60	1.9	O3 *	89.53	42.7	R4 *	5.56
2008-2012	52.3	46.8	L4 *	3.69	56.4	L3 *	3.19	27.1	O4 *	62.61
2009-2013	59.8	46.5	L3 *	11.39	117.0	O3 *	5.19	0.7	O2 *	91.28

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONA 230kV Conventional Air Breakers

T-Cut: None
Placement Band: 1957-1982
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1975-2013	42.0	46.9	L3 *	6.99	38.3	R1.5 *	10.98	42.3	R4 *	3.28
1977-2013	41.8	46.9	L3 *	6.58	36.0	R1 *	14.92	42.1	R4 *	3.29
1979-2013	42.8	46.9	L3 *	6.40	35.5	R1 *	17.49	43.0	R4 *	3.33
1981-2013	44.5	46.8	L3 *	7.05	36.4	R1 *	18.65	43.9	S4 *	3.72
1983-2013	44.5	46.8	L3 *	6.58	35.6	R1 *	20.05	43.6	R4 *	4.07
1985-2013	44.6	46.7	L3 *	6.16	32.7	SC *	25.86	43.6	R4 *	4.08
1987-2013	44.5	46.6	S3 *	5.66	29.4	SC *	32.37	43.5	R4 *	4.18
1989-2013	44.4	46.5	S3 *	5.23	25.6	O3 *	39.74	43.3	R4 *	4.37
1991-2013	44.2	46.3	S3 *	4.72	21.6	O4 *	47.62	43.0	R4 *	4.57
1993-2013	44.0	46.3	L4 *	4.29	16.7	O4 *	57.19	42.6	R4 *	5.03
1995-2013	43.6	46.4	L4 *	3.91	12.6	O4 *	64.93	42.6	R4 *	4.64
1997-2013	43.5	46.2	L4 *	3.80	9.9	O4 *	70.24	41.1	R3 *	7.53
1999-2013	38.8	45.9	L4 *	7.31	6.8	O4 *	72.78	18.2	O4	49.82
2001-2013	38.1	46.1	S4 *	8.62	4.8	O4	76.04	3.3	O4 *	78.97
2003-2013	50.4	48.8	L4 *	6.93	8.8	O4	70.86	0.6	O2 *	86.70
2005-2013	49.5	47.9	L4 *	6.21	6.5	O4	75.13	0.3	SC *	87.32
2007-2013	54.7	47.4	L4 *	3.19	47.3	L4 *	3.20	0.3	SC *	92.06
2009-2013	59.8	46.5	L3 *	11.39	117.0	O3 *	5.19	0.7	O2 *	91.28
2011-2013	82.3	55.5	L4 *	4.13	57.8	L4 *	4.29	0.3	SC *	97.12
2013-2013	75.1	49.1	L4 *	10.61	111.9	O3 *	12.43	0.3	SC *	96.57

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONA 230kV Conventional Air Breakers

T-Cut: None

Placement Band: 1957-1982

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1975-1976	98.8	192.3	SQ*	1.75	192.9	S6*	1.40	30.6	S4*	0.88
1975-1978	94.7	174.9	R2.5*	4.38	180.8	R3*	2.56	30.0	R4*	1.54
1975-1980	92.5	167.9	R1.5*	5.64	176.1	R2.5*	2.81	31.3	R4*	1.73
1975-1982	93.4	174.8	R2.5*	4.93	178.9	R3*	2.89	33.1	R4*	1.32
1975-1984	90.5	176.2	R2.5*	3.53	178.2	R3*	2.82	34.7	R4*	1.22
1975-1986	90.7	178.8	R3*	2.92	179.9	R3*	2.44	38.0	R4*	1.13
1975-1988	92.1	180.0	R3*	2.77	180.7	R3*	2.45	41.2	R4*	1.01
1975-1990	92.9	180.6	R3*	2.77	120.4	R3*	2.62	44.5	R4*	1.25
1975-1992	86.1	180.0	R3*	2.50	51.2	R2	4.07	41.2	R4*	1.69
1975-1994	79.3	127.1	SC	3.06	46.9	R2	4.30	41.7	R3	2.06
1975-1996	78.0	104.6	L0	3.14	50.1	R2	3.33	47.0	R2.5	2.87
1975-1998	80.4	116.8	SC	2.65	55.3	R2	2.86	60.9	R1.5*	2.99
1975-2000	53.4	72.2	L1.5*	4.42	43.9	R2*	7.01	42.7	R4*	4.14
1975-2002	0.0	48.2	L2*	11.24	32.4	R1*	19.60	36.5	R4*	11.20
1975-2004	0.0	50.7	L2*	11.59	34.3	R1*	17.52	37.4	R4*	10.09
1975-2006	0.0	51.3	L2*	11.49	36.2	R1.5*	15.17	38.5	R4*	8.10
1975-2008	0.0	47.5	S1.5*	11.64	34.2	R1*	17.99	38.0	R3*	9.17
1975-2010	22.9	46.0	L3*	9.44	34.8	R1*	15.73	39.2	R4*	5.49
1975-2012	39.1	47.2	S1.5*	7.20	37.6	R1.5*	11.65	41.6	R4*	3.10
1975-2013	42.0	46.9	L3*	6.99	38.3	R1.5*	10.98	42.3	R4*	3.28

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONA 230kV Conventional Air Breakers

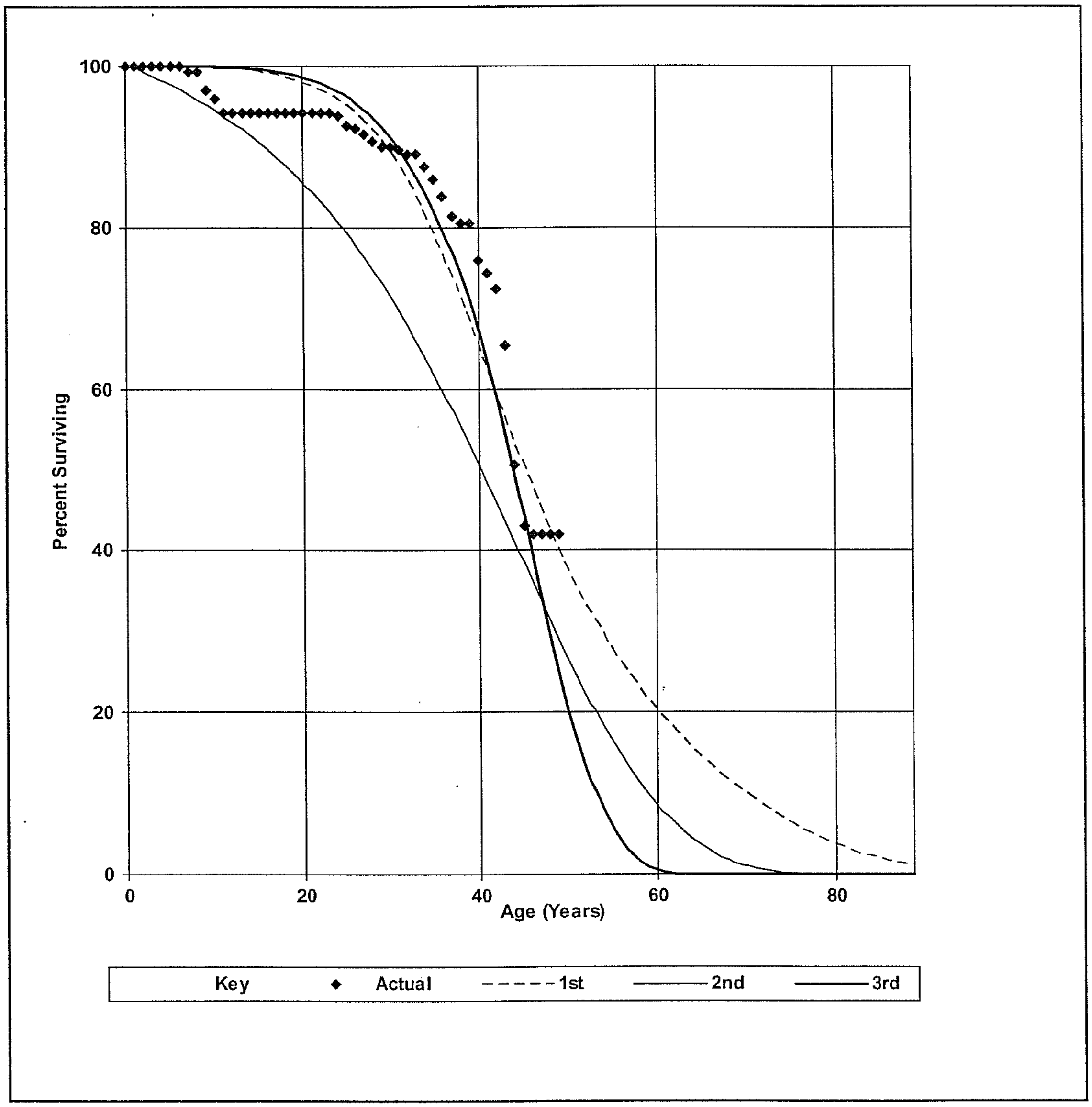
T-Cut: None

Placement Band: 1957-1982 Observation Band: 1975-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 46.9-L3 2nd: 38.3-R1.5 3rd: 42.3-R4



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONA 230kV Conventional Air Breakers

T-Cut: None

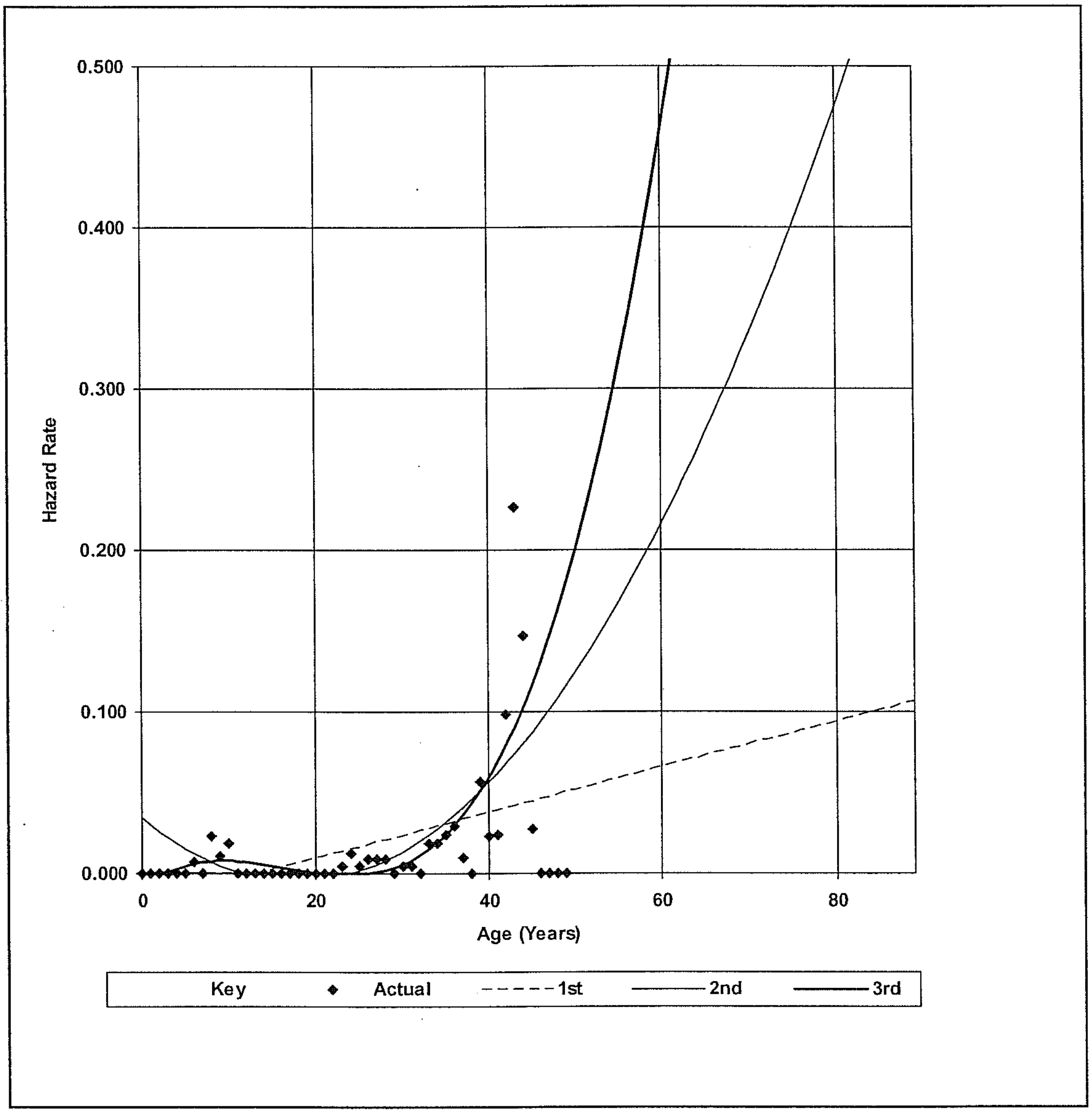
Placement Band: 1957-1982 Observation Band: 1975-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 46.9-L3 2nd: 38.3-R1.5 3rd: 42.3-R4



Schedule E

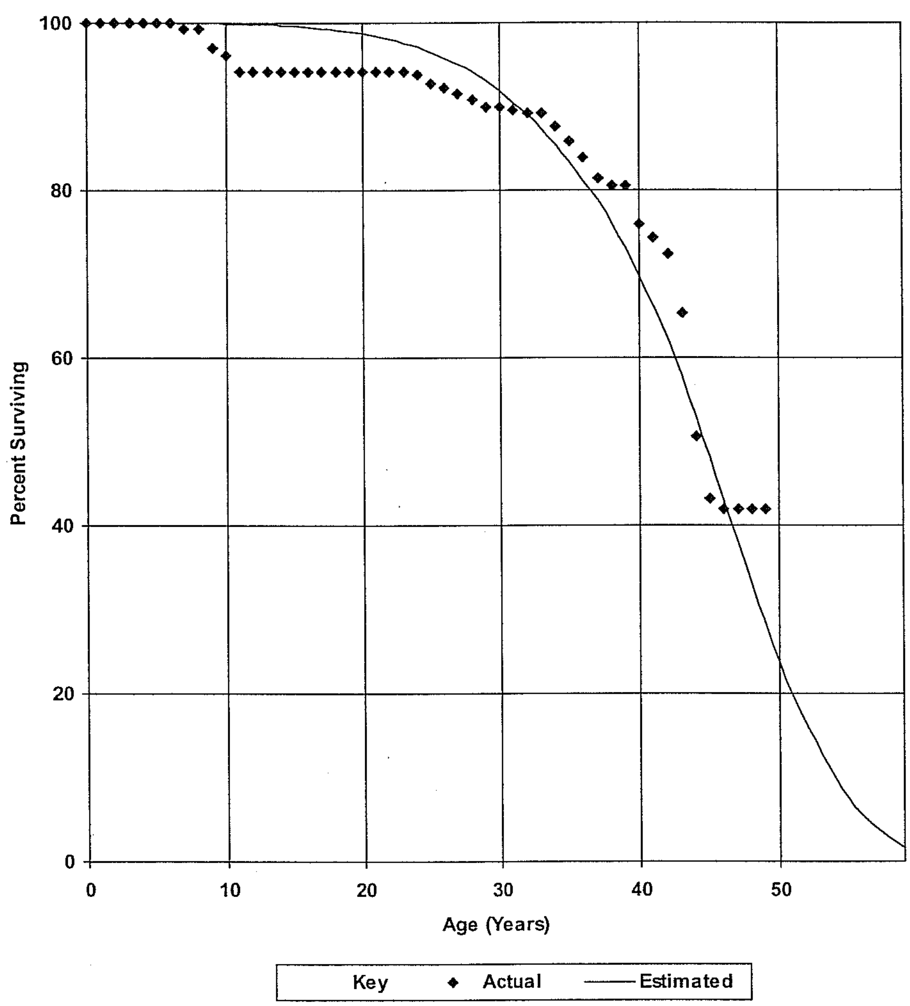
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONA 230kV Conventional Air Breakers

T-Cut: None
Placement Band: 1957-1982
Observation Band: 1975-2013
43.0-R4

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONO 230kV Conventional Oil Breakers

Placement Band: 1941 - 1980
Observation Band: 1988 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	0	0	0.00000	1.00000	1.00000
0.5	0	0	0.00000	1.00000	1.00000
1.5	0	0	0.00000	1.00000	1.00000
2.5	0	0	0.00000	1.00000	1.00000
3.5	0	0	0.00000	1.00000	1.00000
4.5	0	0	0.00000	1.00000	1.00000
5.5	0	0	0.00000	1.00000	1.00000
6.5	0	0	0.00000	1.00000	1.00000
7.5	6	0	0.00000	1.00000	1.00000
8.5	13	0	0.00000	1.00000	1.00000
9.5	23	1	0.04348	0.95652	1.00000
10.5	25	0	0.00000	1.00000	0.95652
11.5	60	0	0.00000	1.00000	0.95652
12.5	98	0	0.00000	1.00000	0.95652
13.5	113	0	0.00000	1.00000	0.95652
14.5	136	1	0.00735	0.99265	0.95652
15.5	142	0	0.00000	1.00000	0.94949
16.5	159	0	0.00000	1.00000	0.94949
17.5	165	1	0.00606	0.99394	0.94949
18.5	184	5	0.02717	0.97283	0.94373
19.5	183	4	0.02186	0.97814	0.91809
20.5	185	4	0.02162	0.97838	0.89802
21.5	182	3	0.01648	0.98352	0.87860
22.5	180	0	0.00000	1.00000	0.86412
23.5	180	0	0.00000	1.00000	0.86412
24.5	195	3	0.01538	0.98462	0.86412
25.5	194	1	0.00515	0.99485	0.85083
26.5	209	0	0.00000	1.00000	0.84644
27.5	215	2	0.00930	0.99070	0.84644
28.5	213	0	0.00000	1.00000	0.83857
29.5	213	5	0.02347	0.97653	0.83857
30.5	208	0	0.00000	1.00000	0.81888
31.5	215	4	0.01860	0.98140	0.81888
32.5	212	1	0.00472	0.99528	0.80365
33.5	214	1	0.00467	0.99533	0.79986
34.5	217	3	0.01382	0.98618	0.79612
35.5	209	4	0.01914	0.98086	0.78511

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONO 230kV Conventional Oil Breakers

Placement Band: 1941 - 1980
Observation Band: 1988 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	202	9	0.04455	0.95545	0.77009
37.5	172	2	0.01163	0.98837	0.73578
38.5	160	1	0.00625	0.99375	0.72722
39.5	169	5	0.02959	0.97041	0.72268
40.5	146	3	0.02055	0.97945	0.70130
41.5	138	1	0.00725	0.99275	0.68689
42.5	123	3	0.02439	0.97561	0.68191
43.5	114	5	0.04386	0.95614	0.66528
44.5	94	5	0.05319	0.94681	0.63610
45.5	87	5	0.05747	0.94253	0.60226
46.5	84	8	0.09524	0.90476	0.56765
47.5	75	19	0.25333	0.74667	0.51359
48.5	56	11	0.19643	0.80357	0.38348
49.5	45	4	0.08889	0.91111	0.30815
50.5	39	5	0.12821	0.87179	0.28076
51.5	34	7	0.20588	0.79412	0.24477
52.5	19	0	0.00000	1.00000	0.19437
53.5	17	1	0.05882	0.94118	0.19437
54.5	16	5	0.31250	0.68750	0.18294
55.5	11	0	0.00000	1.00000	0.12577
56.5	11	0	0.00000	1.00000	0.12577
57.5	10	0	0.00000	1.00000	0.12577
58.5	10	2	0.20000	0.80000	0.12577
59.5	8	0	0.00000	1.00000	0.10062
60.5	7	1	0.14286	0.85714	0.10062
61.5	6	0	0.00000	1.00000	0.08624
62.5	6	0	0.00000	1.00000	0.08624
63.5	4	0	0.00000	1.00000	0.08624
64.5	2	1	0.50000	0.50000	0.08624
65.5	0	0	0.00000	1.00000	0.04312

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONO 230kV Conventional Oil Breakers

T-Cut: None

Placement Band: 1941-1980

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-1992	68.0	71.7	L0	3.88	141.7	SC *	2.12	54.1	R2 *	2.52
1989-1993	73.0	72.5	L1.5 *	4.33	56.1	R1.5	3.70	116.6	SC *	16.06
1990-1994	61.9	65.8	L2 *	11.05	44.8	R1	7.77	69.5	O4 *	19.27
1991-1995	60.4	55.4	L3 *	4.38	40.8	R0.5	19.40	48.4	R3	6.41
1992-1996	0.0	45.1	L3 *	14.70	15.4	O4 *	59.72	46.0	R4 *	8.54
1993-1997	0.0	42.5	L3 *	17.75	9.3	O4 *	69.71	44.9	R4 *	7.15
1994-1998	0.0	40.6	S3 *	18.10	5.5	O4 *	75.06	43.9	R4 *	4.96
1995-1999	0.0	39.9	L4 *	17.59	2.7	O4 *	77.86	43.3	R4 *	2.25
1996-2000	0.0	39.5	L4 *	15.25	1.8	O3 *	77.49	42.7	R4 *	3.01
1997-2001	7.7	41.1	L4 *	14.52	3.0	O4 *	81.47	44.9	R5 *	3.65
1998-2002	7.3	41.8	L4 *	12.84	4.0	O4 *	79.78	44.6	R5 *	3.33
1999-2003	10.9	43.7	L4 *	8.97	6.5	O4	73.59	20.5	O4	47.77
2000-2004	15.3	45.0	L4 *	6.82	21.5	O4	45.58	0.9	O3	82.83
2001-2005	19.2	48.1	L4 *	6.37	48.0	L4 *	6.41	0.8	O2 *	81.05
2002-2006	29.3	53.0	L3 *	6.92	83.2	O3 *	6.59	2.7	O4 *	80.38
2003-2007	24.2	52.7	L2 *	10.64	110.1	O3 *	10.59	62.2	O4 *	31.62
2004-2008	18.5	52.6	L3 *	16.62	101.5	O3 *	15.82	16.6	O4 *	62.84
2005-2009	22.0	52.4	L3 *	3.54	55.2	L3 *	3.33	52.2	S3 *	3.14
2006-2010	13.2	49.4	L4 *	3.30	52.2	L4 *	3.11	0.6	O2 *	80.69
2007-2011	12.9	49.1	L4 *	4.12	51.5	L4 *	4.08	0.3	SC *	80.40
2008-2012	5.7	49.2	S4 *	6.11	49.2	S4 *	6.08	0.3	SC *	80.11
2009-2013	1.6	49.9	S4 *	9.25	50.0	S4 *	9.32	0.3	SC *	77.93

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONO 230kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1941-1980
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-2013	4.3	46.6	L3 *	7.22	31.0	SC	22.24	26.9	O3	29.12
1990-2013	3.7	46.6	L3 *	12.24	29.8	SC	17.70	17.1	O4 *	38.97
1992-2013	4.4	46.4	S3 *	6.00	29.5	SC	28.04	10.2	O4 *	60.56
1994-2013	4.1	46.1	S3 *	5.90	25.9	O3	32.84	3.7	O4 *	70.19
1996-2013	3.8	46.0	L4 *	7.11	23.1	O3	34.99	1.4	O3 *	71.61
1998-2013	5.2	47.6	L4 *	4.97	47.5	L4 *	4.27	2.0	O4 *	76.55
2000-2013	6.3	48.7	L4 *	4.10	48.6	L4 *	3.90	1.8	O3 *	76.55
2002-2013	7.6	50.0	L4 *	3.41	49.9	L4 *	3.38	3.1	O4 *	75.57
2004-2013	7.0	50.5	L4 *	4.21	50.3	L4 *	4.15	1.4	O3	77.45
2006-2013	5.4	50.2	L4 *	4.16	50.2	L4 *	4.15	0.7	O2	79.67
2008-2013	3.8	50.3	S4 *	6.15	50.3	S4 *	6.27	0.3	SC *	79.76
2010-2013	0.9	49.9	S4 *	11.07	49.8	L5 *	10.55	0.3	SC *	81.48
2012-2013	10.6	50.8	S4 *	15.40	4.1	O4	81.77	0.3	SC	87.41

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONO 230kV Conventional Oil Breakers

T-Cut: None

Placement Band: 1941-1980

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-1989	72.7	107.6	O3*	10.90	126.6	SC*	8.55	45.3	R1*	7.50
1988-1991	73.3	129.5	SC*	7.55	147.1	SC*	2.72	77.2	R1*	2.51
1988-1993	70.9	72.7	L0.5	3.41	111.2	O3*	2.51	53.9	R2.5*	2.65
1988-1995	61.5	61.2	L2*	3.63	44.4	R0.5	13.42	49.8	R3*	4.65
1988-1997	0.0	46.5	L3*	9.51	26.0	O3*	34.57	44.5	R4*	5.60
1988-1999	0.0	44.7	L3*	11.92	20.2	O4*	44.86	44.2	R4*	2.54
1988-2001	0.0	44.0	L3*	11.71	18.9	O4*	46.52	43.9	R4*	2.57
1988-2003	8.0	44.5	L3*	9.80	20.8	O4*	42.40	44.2	R4*	3.08
1988-2005	12.0	45.4	L3*	8.42	24.0	O3*	35.75	44.0	R3*	3.27
1988-2007	12.6	45.9	L3*	7.28	28.8	SC	26.39	36.2	R0.5	13.30
1988-2009	8.6	46.5	L3*	7.01	29.5	SC	25.16	34.1	SC	17.20
1988-2011	10.3	46.5	L3*	7.43	30.6	SC	23.28	26.4	O3	30.35
1988-2013	4.3	46.6	L3*	7.22	31.0	SC	22.24	26.9	O3	29.12

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONO 230kV Conventional Oil Breakers

T-Cut: None

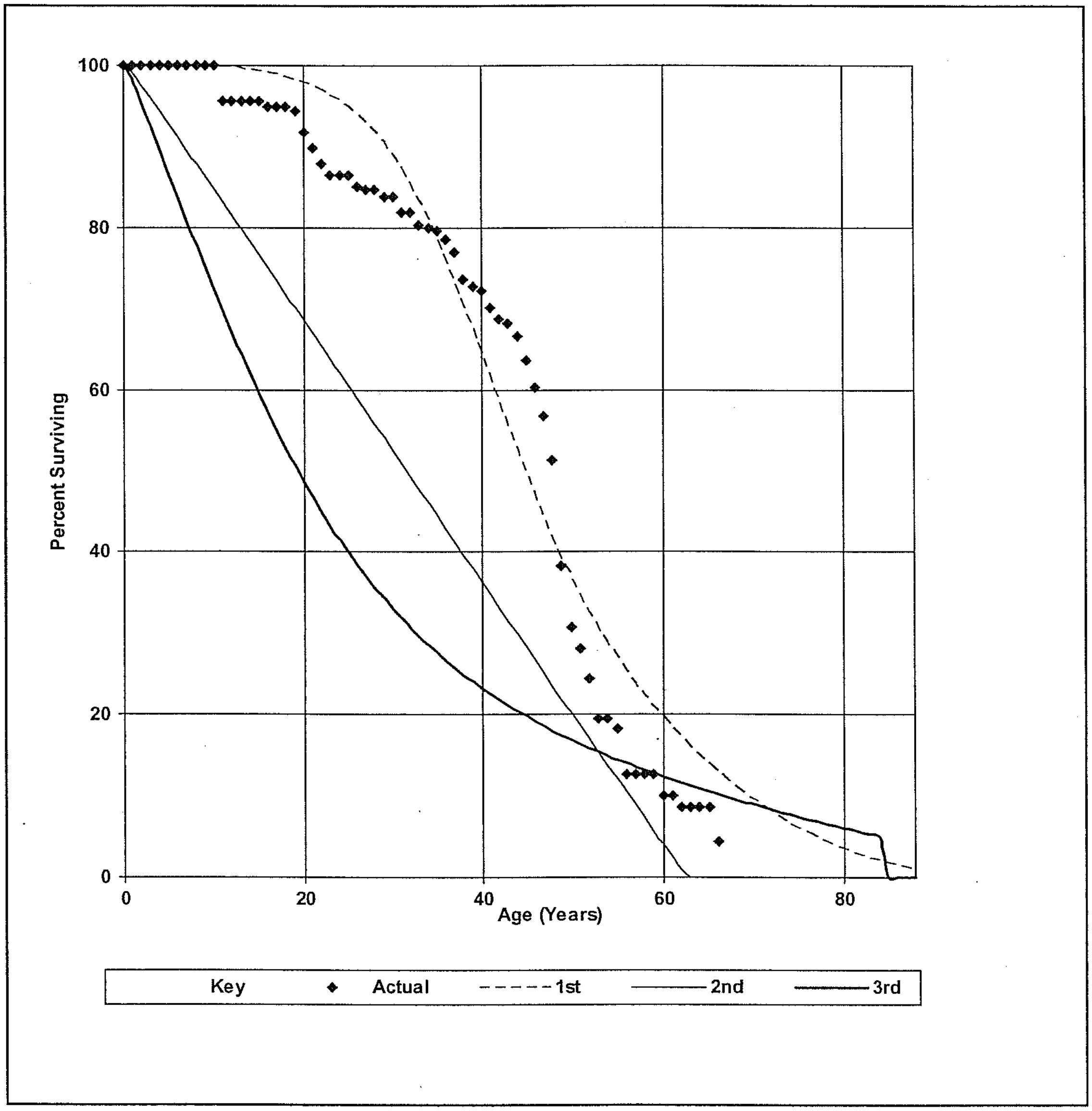
Placement Band: 1941-1980 Observation Band: 1988-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 46.6-L3 2nd: 31.0-SC 3rd: 26.9-O3



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONO 230kV Conventional Oil Breakers

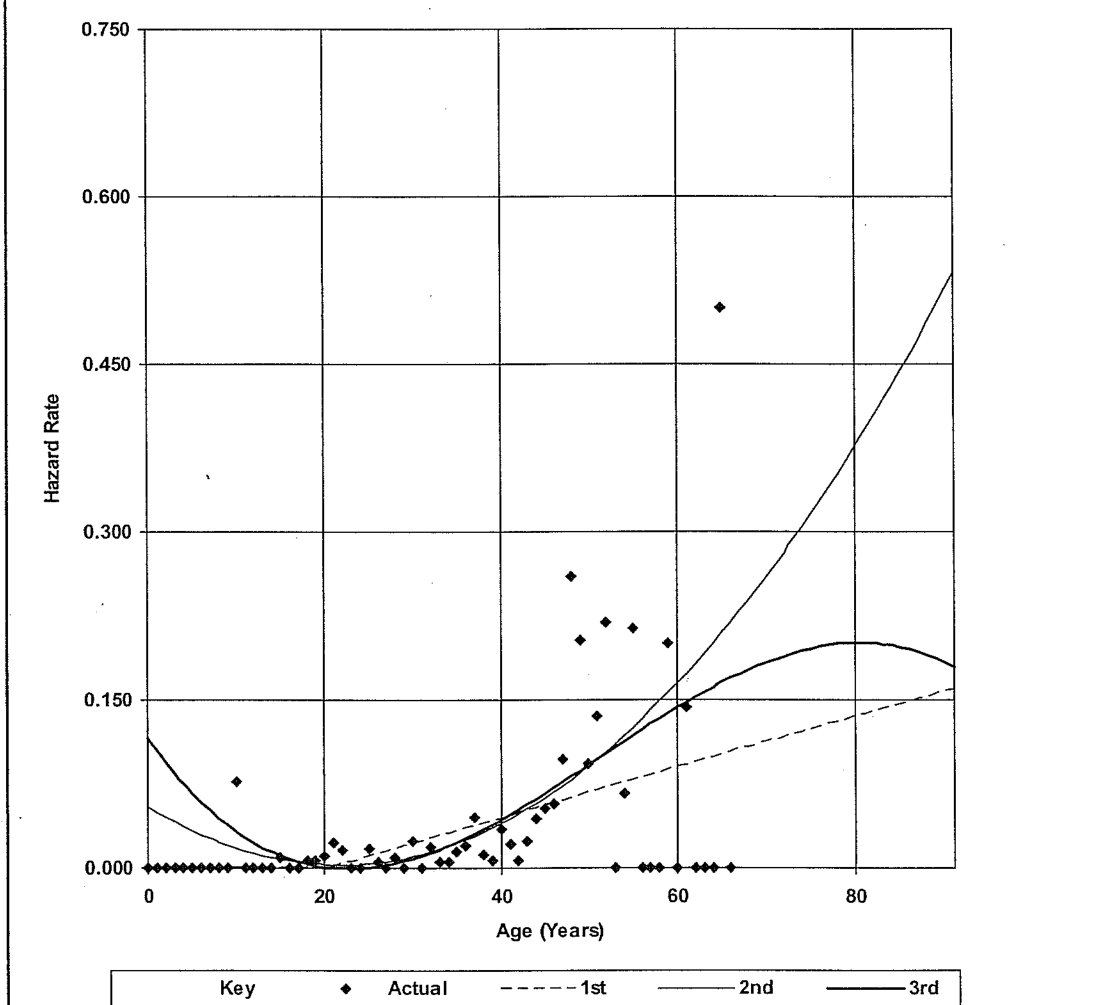
T-Cut: None

Placement Band: 1947-1980 Observation Band: 1989-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function 1st: 46.9-L3 2nd: 32.1-SC 3rd: 22.2-O4



Schedule E

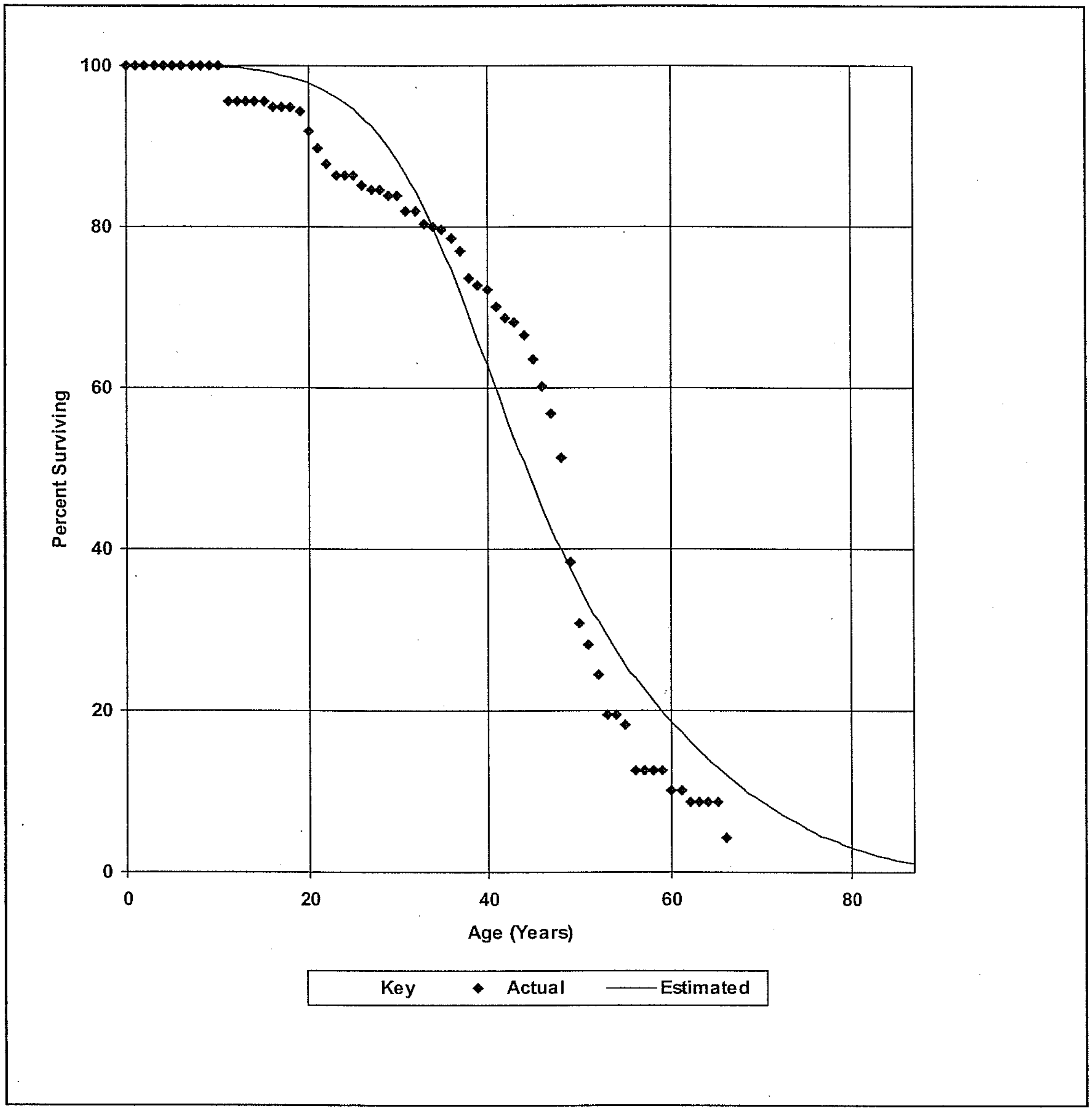
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONO 230kV Conventional Oil Breakers

T-Cut: None
Placement Band: 1941-1980
Observation Band: 1988-2013
46.0-L3

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONS 230kV Conventional and GIS SF6 Breakers

Placement Band: 1977 - 2013
Observation Band: 1979 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	347	0	0.00000	1.00000	1.00000
0.5	375	0	0.00000	1.00000	1.00000
1.5	363	9	0.02479	0.97521	1.00000
2.5	329	2	0.00608	0.99392	0.97521
3.5	314	0	0.00000	1.00000	0.96928
4.5	309	6	0.01942	0.98058	0.96928
5.5	283	0	0.00000	1.00000	0.95046
6.5	212	3	0.01415	0.98585	0.95046
7.5	191	0	0.00000	1.00000	0.93701
8.5	185	0	0.00000	1.00000	0.93701
9.5	166	1	0.00602	0.99398	0.93701
10.5	162	0	0.00000	1.00000	0.93136
11.5	157	5	0.03185	0.96815	0.93136
12.5	199	8	0.04020	0.95980	0.90170
13.5	175	3	0.01714	0.98286	0.86545
14.5	167	3	0.01796	0.98204	0.85062
15.5	215	0	0.00000	1.00000	0.83534
16.5	209	16	0.07656	0.92344	0.83534
17.5	187	3	0.01604	0.98396	0.77139
18.5	174	0	0.00000	1.00000	0.75901
19.5	174	3	0.01724	0.98276	0.75901
20.5	168	0	0.00000	1.00000	0.74592
21.5	152	0	0.00000	1.00000	0.74592
22.5	149	0	0.00000	1.00000	0.74592
23.5	148	0	0.00000	1.00000	0.74592
24.5	147	0	0.00000	1.00000	0.74592
25.5	112	0	0.00000	1.00000	0.74592
26.5	112	0	0.00000	1.00000	0.74592
27.5	112	17	0.15179	0.84821	0.74592
28.5	95	6	0.06316	0.93684	0.63270
29.5	89	0	0.00000	1.00000	0.59274
30.5	89	0	0.00000	1.00000	0.59274
31.5	89	1	0.01124	0.98876	0.59274
32.5	79	3	0.03797	0.96203	0.58608
33.5	59	1	0.01695	0.98305	0.56383
34.5	56	2	0.03571	0.96429	0.55427
35.5	51	0	0.00000	1.00000	0.53448

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONS 230kV Conventional and GIS SF6 Breakers

Placement Band: 1977 - 2013
Observation Band: 1979 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	0	0	0.00000	1.00000	0.53448

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONS 230kV Conventional and GIS SF6 Breakers

T-Cut: None
Placement Band: 1977-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1979-1983	96.2	186.0	R4*	2.32	188.0	R5*	1.28	8.1	R5*	1.69
1980-1984	100.0				No Retirements					
1981-1985	85.7	15.6	L2*	2.60	10.4	S3*	3.61	9.6	S4*	3.53
1982-1986	93.8	19.8	L2*	1.77	14.4	S2*	2.17	177.6	R3*	2.29
1983-1987	93.8	24.7	L1.5*	1.37	182.3	R4*	1.18	176.8	R2.5*	4.87
1984-1988	96.0	37.2	L1	1.99	188.6	R5*	0.99	187.1	R4*	1.41
1985-1989	95.8	46.2	L0.5	1.88	184.6	R4*	2.53	186.8	R4*	1.52
1986-1990	100.0				No Retirements					
1987-1991	93.3	34.3	L1.5*	2.19	20.6	S3*	1.83	18.9	R4*	1.84
1988-1992	93.3	38.8	L1.5*	1.75	25.9	S2*	1.29	171.0	R1.5*	1.29
1989-1993	81.3	22.5	L1.5*	7.69	118.6	SC*	13.20	128.3	SC*	10.94
1990-1994	82.7	29.6	L1	4.95	132.2	SC*	12.66	136.0	SC*	9.91
1991-1995	77.5	29.8	L1	3.90	135.4	SC*	8.85	140.3	SC*	6.84
1992-1996	82.0	36.8	L0.5	3.85	146.4	SC*	7.98	149.5	SC*	6.28
1993-1997	79.9	37.7	L0.5	3.90	147.9	SC*	6.52	151.3	SC*	4.85
1994-1998	95.6	54.3	L1.5*	2.19	153.6	SC*	2.58	181.5	R4*	2.95
1995-1999	93.7	59.0	L1.5*	1.71	177.8	R2.5*	3.03	178.5	R3*	3.27
1996-2000	96.8	95.3	L1.5*	0.76	190.2	R5*	1.22	189.9	R5*	1.37
1997-2001	96.5	104.2	L1*	0.83	190.1	R5*	1.32	188.9	R5*	1.42
1998-2002	100.0				No Retirements					
1999-2003	97.8	194.1	SQ*	0.66	193.5	S6*	0.54	65.5	S4*	0.54
2000-2004	98.6	194.1	SQ*	0.88	193.6	S6*	0.93	60.7	R4*	0.96
2001-2005	92.8	182.3	R4*	1.68	183.5	R4*	0.99	183.4	R4*	0.96
2002-2006	88.5	175.9	R2.5*	1.72	176.0	R2.5*	1.10	174.9	R2*	1.11
2003-2007	81.7	160.1	R1*	3.84	157.8	R0.5*	2.64	51.5	R2*	2.74
2004-2008	69.5	38.4	L1.5*	5.47	36.3	S0.5	4.73	36.2	S0.5	4.72
2005-2009	48.9	26.4	O2	10.95	48.7	O4*	11.57	74.6	O4*	10.37
2006-2010	34.8	27.2	O2	6.63	62.4	O4*	7.02	72.5	O4*	5.96
2007-2011	26.9	26.2	O2	6.29	58.7	O4*	5.91	63.2	O4*	5.46
2008-2012	26.6	26.4	L0	5.86	54.6	O4*	7.17	60.4	O4*	6.38
2009-2013	35.5	33.2	O3	6.28	74.7	O4*	5.20	76.0	O4*	5.09

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONS 230kV Conventional and GIS SF6 Breakers

T-Cut: None

Placement Band: 1977-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1979-2013	53.4	42.3	L0	2.74	44.7	L0	2.69	42.2	L0	2.69
1981-2013	53.6	42.3	L0	2.73	47.3	O2 *	2.69	41.0	L0.5	2.69
1983-2013	53.5	42.3	L0	2.73	46.2	O2 *	2.69	41.3	L0.5	2.69
1985-2013	53.4	42.3	L0	2.72	45.6	O2 *	2.68	41.0	L0.5	2.68
1987-2013	53.6	42.3	L0	2.76	45.0	L0	2.71	42.6	L0	2.71
1989-2013	53.6	42.3	L0	2.78	45.6	O2 *	2.73	41.0	L0.5	2.73
1991-2013	53.3	42.2	L0	2.79	44.8	O2	2.73	40.8	L0.5	2.73
1993-2013	53.3	42.3	L0	2.84	43.3	L0	2.76	41.8	L0	2.76
1995-2013	53.4	43.0	L0	2.81	40.4	L0.5	2.82	99.6	O4 *	2.82
1997-2013	52.7	42.8	L0	2.80	40.1	L0.5	2.82	97.1	O4 *	2.83
1999-2013	49.4	41.8	L0	3.50	40.3	L0	3.65	96.9	O4 *	3.71
2001-2013	47.5	39.6	O2	3.26	59.0	O4 *	3.10	98.5	O4 *	3.14
2003-2013	45.9	36.7	O2	3.22	80.0	O4 *	3.15	95.3	O4 *	3.06
2005-2013	44.2	33.2	O2	4.10	77.7	O4 *	5.17	86.4	O4 *	4.93
2007-2013	29.3	29.7	O2	5.68	67.1	O4 *	5.06	72.9	O4 *	4.54
2009-2013	35.5	33.2	O3	6.28	74.7	O4 *	5.20	76.0	O4 *	5.09
2011-2013	53.0	41.4	L0	4.69	86.4	O4 *	4.60	34.6	R0.5	4.08
2013-2013	31.2	53.8	O3	7.70	37.7	SC	8.34	35.8	R0.5	8.53

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONS 230kV Conventional and GIS SF6 Breakers

T-Cut: None

Placement Band: 1977-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1979-1980	87.5	5.1	L2 *	5.31	174.4	R2 *	0.00	174.4	R2 *	0.00
1979-1982	94.1	178.2	R3 *	1.99	186.4	R4 *	0.92	6.5	R5 *	1.58
1979-1984	96.2	186.9	R4 *	2.08	188.9	R5 *	1.08	9.6	R4 *	1.52
1979-1986	90.1	27.0	L0.5	1.62	14.0	R2.5	2.27	13.0	R3	2.35
1979-1988	92.3	172.3	R2 *	1.74	178.1	R3 *	1.31	181.2	R4 *	1.30
1979-1990	94.5	175.2	R2.5 *	1.38	185.9	R4 *	1.21	185.9	R4 *	1.20
1979-1992	88.2	41.0	L1	1.26	29.8	S1	1.29	170.4	R1.5 *	1.25
1979-1994	79.6	30.5	L1	2.53	145.7	SC *	4.86	144.4	SC *	5.00
1979-1996	78.1	36.5	L1	2.78	152.0	SC *	3.56	153.1	SC *	2.86
1979-1998	78.7	43.4	L0.5	3.42	157.4	R0.5 *	2.68	158.4	R1 *	2.03
1979-2000	81.4	57.6	L0.5	3.40	164.0	R1 *	2.32	164.3	R1 *	1.95
1979-2002	85.4	77.9	L0	2.29	168.8	R1.5 *	1.76	169.0	R1.5 *	1.44
1979-2004	85.5	106.9	SC	2.52	170.9	R1.5 *	1.43	171.0	R1.5 *	1.39
1979-2006	85.8	131.3	SC	2.16	169.2	R1.5 *	1.49	169.1	R1.5 *	1.47
1979-2008	70.2	46.6	L1	2.98	41.1	S0.5	2.99	33.9	R2.5 *	2.64
1979-2010	60.9	42.5	L0	3.36	41.3	L0.5	3.24	86.4	O4 *	3.24
1979-2012	55.0	41.8	L0.5	2.87	44.3	L0	2.83	41.8	L0.5	2.82
1979-2013	53.4	42.3	L0	2.74	44.7	L0	2.69	42.2	L0	2.69

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONS 230kV Conventional and GIS SF6 Breakers

T-Cut: None

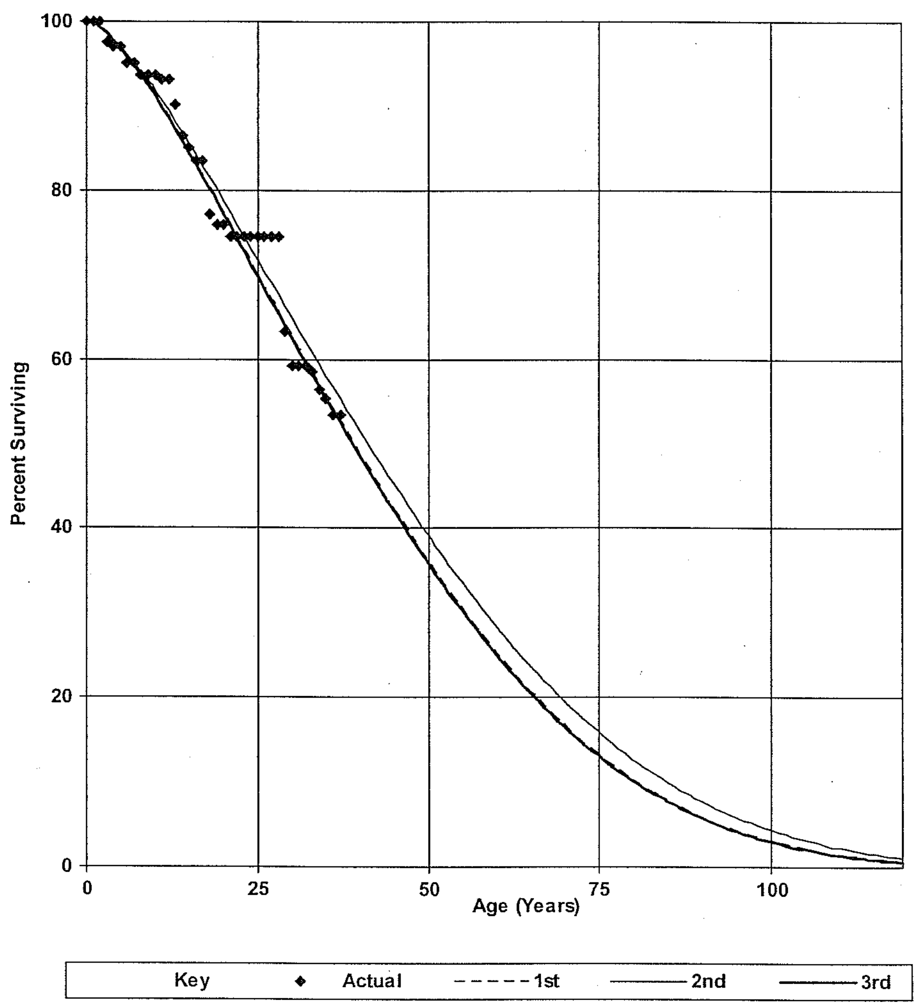
Placement Band: 1977-2013 Observation Band: 1979-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 42.3-L0 2nd: 44.7-L0 3rd: 42.2-L0



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONS 230kV Conventional and GIS SF6 Breakers

T-Cut: None

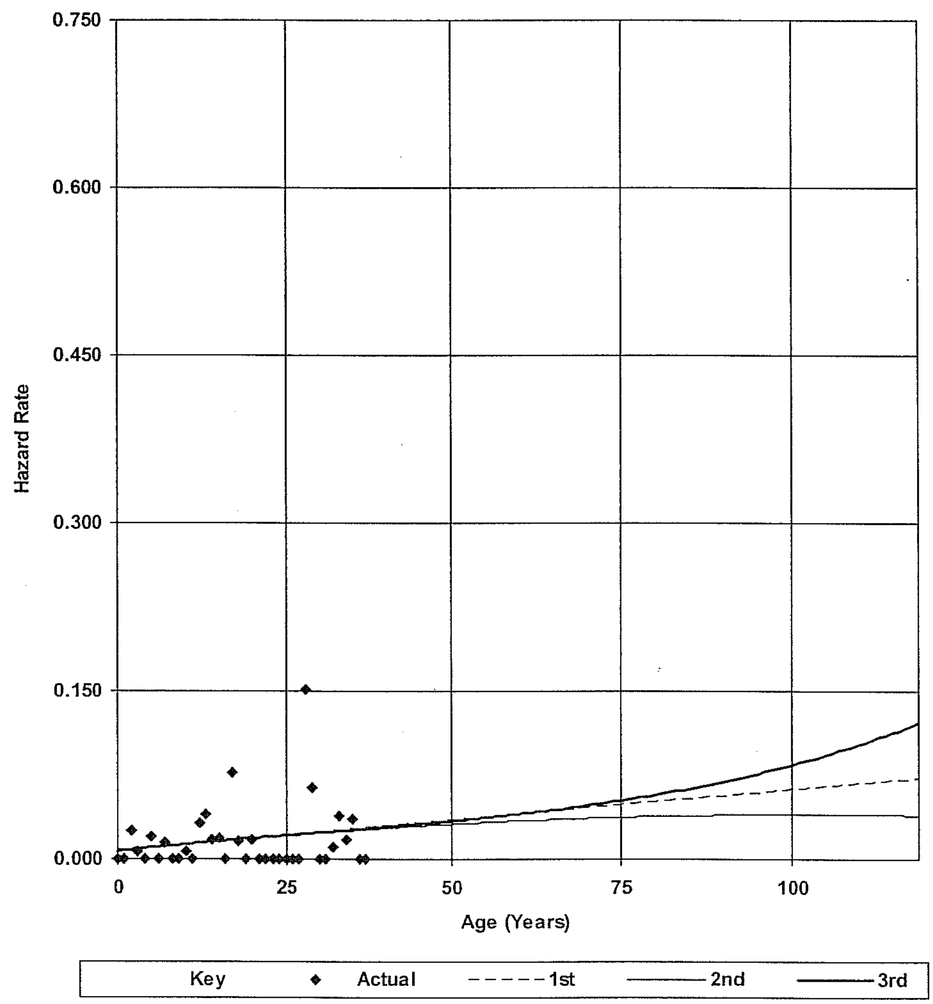
Placement Band: 1977-2013 Observation Band: 1979-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 42.3-L0 2nd: 44.7-L0 3rd: 42.2-L0



Schedule E

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 230CONS 230kV Conventional and GIS SF6 Breakers

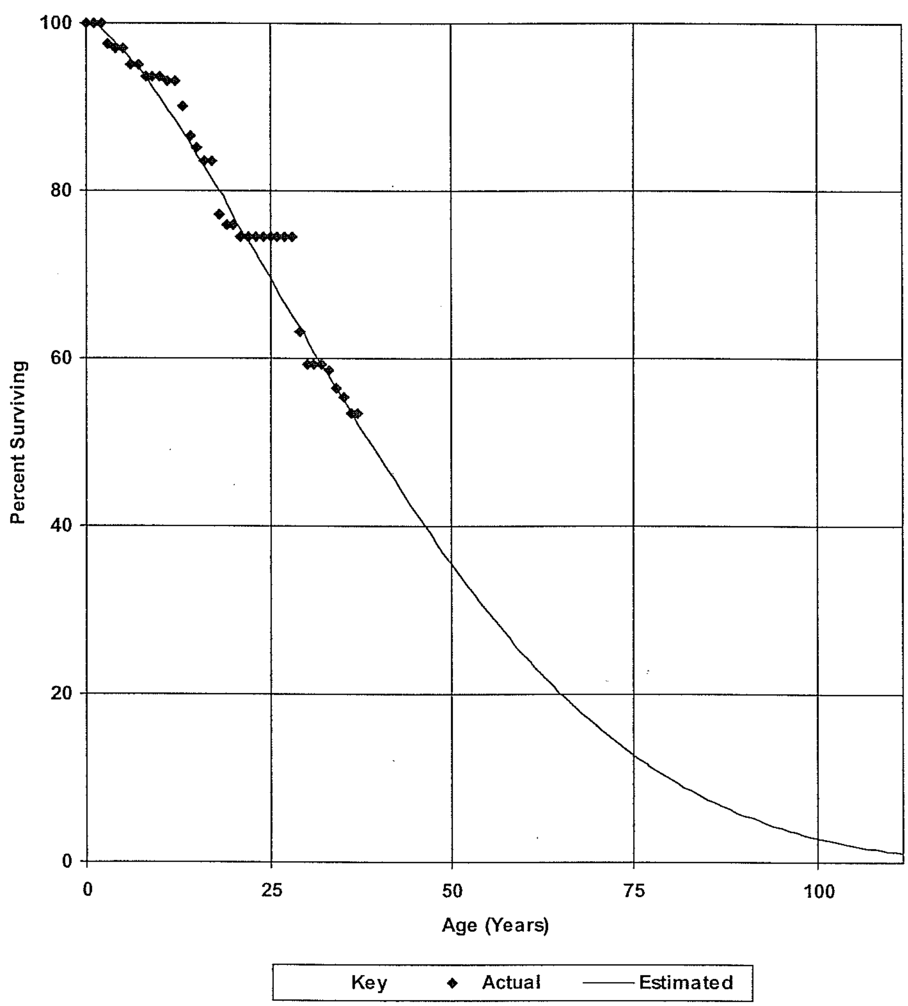
T-Cut: None

Placement Band: 1977-2013

Observation Band: 1979-2013

42.0-L0

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500BRKX 500kV Breakers

Placement Band: 1968 - 2012
Observation Band: 1987 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	75	0	0.00000	1.00000	1.00000
0.5	90	1	0.01111	0.98889	1.00000
1.5	88	0	0.00000	1.00000	0.98889
2.5	88	1	0.01136	0.98864	0.98889
3.5	96	0	0.00000	1.00000	0.97765
4.5	58	1	0.01724	0.98276	0.97765
5.5	41	0	0.00000	1.00000	0.96080
6.5	49	1	0.02041	0.97959	0.96080
7.5	73	0	0.00000	1.00000	0.94119
8.5	93	2	0.02151	0.97849	0.94119
9.5	100	1	0.01000	0.99000	0.92095
10.5	99	2	0.02020	0.97980	0.91174
11.5	97	0	0.00000	1.00000	0.89332
12.5	97	0	0.00000	1.00000	0.89332
13.5	158	7	0.04430	0.95570	0.89332
14.5	161	1	0.00621	0.99379	0.85374
15.5	176	6	0.03409	0.96591	0.84844
16.5	224	13	0.05804	0.94196	0.81951
17.5	208	0	0.00000	1.00000	0.77195
18.5	211	0	0.00000	1.00000	0.77195
19.5	211	0	0.00000	1.00000	0.77195
20.5	193	0	0.00000	1.00000	0.77195
21.5	191	0	0.00000	1.00000	0.77195
22.5	190	4	0.02105	0.97895	0.77195
23.5	184	0	0.00000	1.00000	0.75570
24.5	184	0	0.00000	1.00000	0.75570
25.5	174	0	0.00000	1.00000	0.75570
26.5	174	0	0.00000	1.00000	0.75570
27.5	174	0	0.00000	1.00000	0.75570
28.5	153	0	0.00000	1.00000	0.75570
29.5	153	13	0.08497	0.91503	0.75570
30.5	140	0	0.00000	1.00000	0.69149
31.5	140	9	0.06429	0.93571	0.69149
32.5	131	4	0.03053	0.96947	0.64704
33.5	105	0	0.00000	1.00000	0.62728
34.5	89	0	0.00000	1.00000	0.62728
35.5	81	1	0.01235	0.98765	0.62728

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500BRKX 500kV Breakers

Placement Band: 1968 - 2012
Observation Band: 1987 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	38	0	0.00000	1.00000	0.61954
37.5	38	2	0.05263	0.94737	0.61954
38.5	36	3	0.08333	0.91667	0.58693
39.5	33	0	0.00000	1.00000	0.53802
40.5	10	3	0.30000	0.70000	0.53802
41.5	0	0	0.00000	1.00000	0.37661

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500BRKX 500kV Breakers

T-Cut: None

Placement Band: 1968-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-1991	90.1	143.9	SC *	16.71	172.3	R2 *	3.03	26.9	R4 *	1.95
1988-1992	64.0	139.5	SC *	7.77	148.8	SC *	8.76	28.0	R2 *	11.36
1989-1993	62.5	123.4	SC *	7.51	127.8	SC *	6.31	23.3	R0.5 *	4.97
1990-1994	34.9	18.2	O3	11.22	74.3	O4 *	4.55	78.2	O4 *	5.65
1991-1995	52.6	23.7	O3	15.10	89.0	O4 *	9.60	92.1	O4 *	7.94
1992-1996	53.8	24.6	O2	11.10	96.3	O4 *	7.08	58.0	O4 *	7.57
1993-1997	61.8	28.6	O3	14.38	105.4	O4 *	10.23	78.5	O4 *	10.67
1994-1998	60.2	33.1	O3	12.74	113.5	O3 *	7.51	55.3	SC *	8.37
1995-1999	92.1	70.9	L2 *	1.58	49.6	S2 *	1.68	180.7	R3 *	1.81
1996-2000	96.2	76.3	L1.5 *	1.68	59.4	S1.5 *	1.70	184.5	R4 *	2.61
1997-2001	100.0				No Retirements					
1998-2002	100.0				No Retirements					
1999-2003	97.0	189.5	R5 *	2.10	192.4	SQ *	0.71	51.1	R4 *	1.12
2000-2004	97.0	188.0	R5 *	2.70	191.0	R5 *	1.17	51.0	R4 *	1.27
2001-2005	92.9	186.4	R4 *	2.20	189.2	R5 *	2.15	53.2	R4 *	2.22
2002-2006	31.1	77.7	L2 *	10.08	35.3	R1 *	19.91	37.1	R4 *	8.86
2003-2007	0.0	67.4	S1.5 *	16.52	30.5	SC *	28.65	36.0	R4 *	12.56
2004-2008	0.0	66.2	L3 *	16.61	34.0	R0.5 *	27.27	38.4	R4 *	13.81
2005-2009	0.0	51.9	L2 *	13.74	32.7	R0.5 *	20.13	32.1	R1 *	19.35
2006-2010	0.0	41.6	L2 *	13.27	38.8	R3 *	10.29	77.7	O4 *	10.45
2007-2011	65.6	41.0	L1.5 *	14.16	40.3	L1.5	13.78	125.6	SC *	8.00
2008-2012	60.5	37.4	L0.5	16.88	40.3	L0.5 *	17.49	114.5	O3 *	7.73
2009-2013	36.9	34.9	L0.5	14.14	35.4	L0.5	14.63	98.0	O4 *	5.65

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500BRKX 500kV Breakers

T-Cut: None

Placement Band: 1968-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-2013	37.7	48.2	L0	3.46	38.6	R0.5	3.77	34.8	R1 *	3.01
1989-2013	37.1	48.0	L0	3.58	38.5	R0.5	3.64	34.4	R1 *	3.05
1991-2013	37.1	47.8	L0	3.59	38.7	R0.5	3.70	34.3	R1 *	3.51
1993-2013	38.0	47.6	L0.5	3.54	39.0	R0.5	4.27	34.3	R1 *	4.91
1995-2013	46.6	52.1	L2 *	3.96	43.1	R3 *	2.83	42.0	R3	2.76
1997-2013	46.7	52.5	L2 *	4.12	42.9	R3 *	2.86	41.9	R3	2.73
1999-2013	46.3	51.7	L2 *	4.12	42.6	R3 *	2.92	41.5	R3	2.89
2001-2013	45.6	50.4	L2 *	4.19	42.4	R3 *	2.90	40.9	R3	3.05
2003-2013	44.6	48.3	L2 *	4.62	42.0	R2.5	2.94	40.3	R2.5	3.50
2005-2013	43.8	45.5	L1.5 *	6.69	41.4	R2.5	3.34	41.1	R2.5	3.50
2007-2013	44.4	41.6	L1 *	10.85	39.4	R1.5	8.21	89.9	O4 *	4.81
2009-2013	36.9	34.9	L0.5	14.14	35.4	L0.5	14.63	98.0	O4 *	5.65
2011-2013	41.0	48.0	L1	7.34	44.7	R2.5 *	15.12	32.4	R0.5 *	10.27
2013-2013	51.3	43.7	L2 *	9.30	42.0	R3 *	11.91	24.0	L0 *	32.11

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500BRKX 500kV Breakers

T-Cut: None

Placement Band: 1968-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-1988	90.9	165.9	R1 *	8.33	184.5	R4 *	2.03	24.0	R4 *	1.56
1987-1990	91.9	145.3	SC *	17.30	173.3	R2 *	3.85	25.3	R4 *	2.96
1987-1992	78.8	140.9	SC *	9.90	151.9	SC *	4.58	28.5	R2.5 *	2.34
1987-1994	53.2	23.1	O2	9.42	104.2	O4 *	3.93	107.6	O4 *	4.58
1987-1996	60.5	29.7	O2	8.11	117.9	SC *	3.02	118.3	SC *	2.96
1987-1998	65.0	49.9	O3	8.40	132.2	SC *	2.01	53.6	SC *	2.36
1987-2000	70.8	108.5	O4 *	9.41	139.8	SC *	2.34	41.4	R1 *	2.93
1987-2002	73.9	125.8	SC *	9.79	144.2	SC *	2.60	39.3	R1 *	3.04
1987-2004	74.8	130.8	SC *	9.99	145.0	SC *	3.00	38.7	R1 *	2.92
1987-2006	25.1	132.9	SC *	10.28	140.7	SC *	8.72	33.1	R1.5 *	7.16
1987-2008	0.0	135.6	SC *	14.26	138.9	SC *	13.99	33.9	R1.5 *	10.50
1987-2010	0.0	49.4	L0	9.21	37.2	R0.5	9.41	33.4	R1.5 *	8.05
1987-2012	53.9	49.7	L0	2.41	39.4	R0.5	3.21	35.0	R1	2.82
1987-2013	37.7	48.2	L0	3.46	38.6	R0.5	3.77	34.8	R1 *	3.01

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500BRKX 500kV Breakers

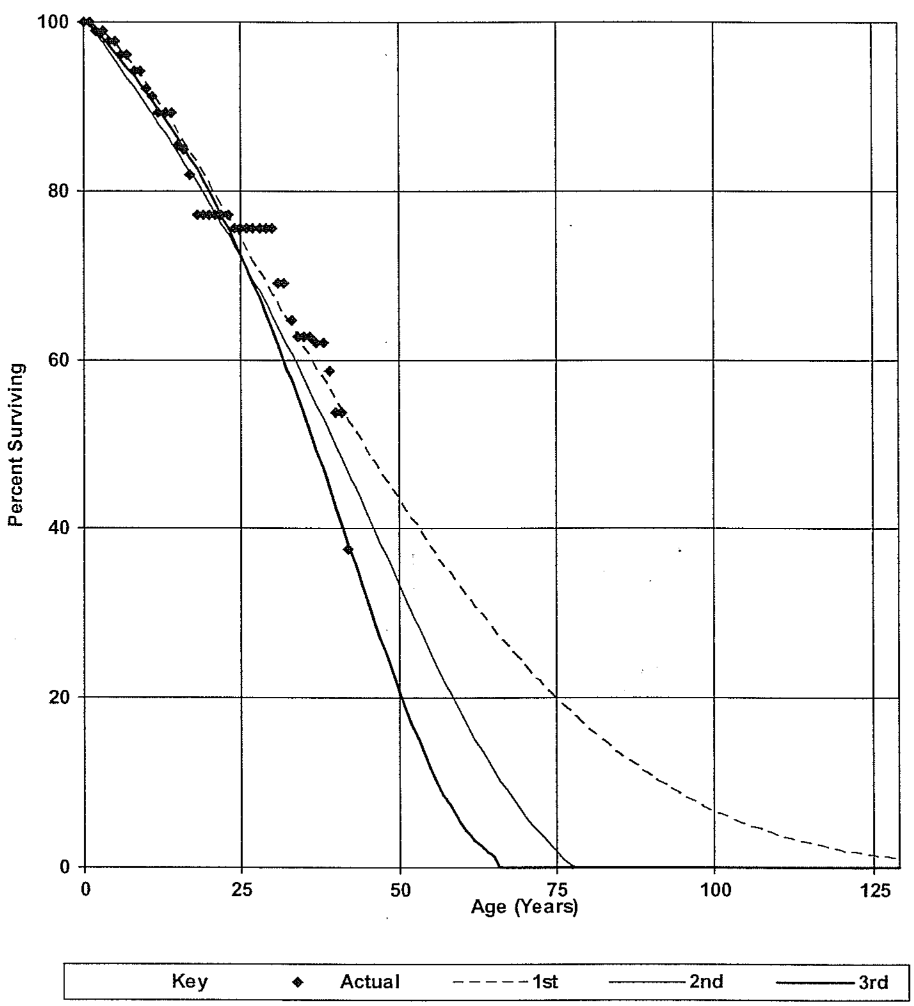
T-Cut: None

Placement Band: 1968-2012 Observation Band: 1987-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 48.2-L0 2nd: 38.6-R0.5 3rd: 34.8-R1



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Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500BRKX 500kV Breakers

T-Cut: None

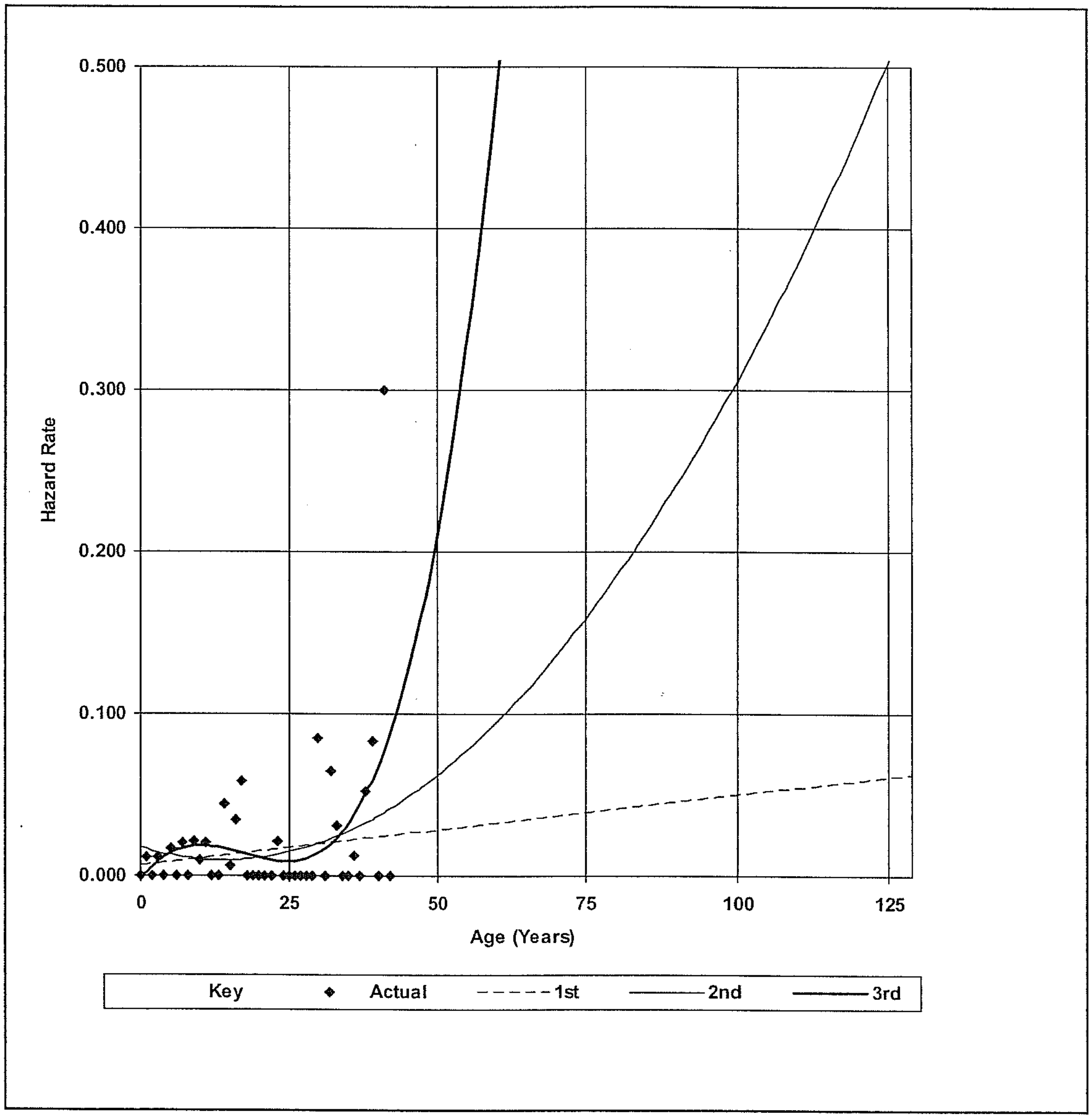
Placement Band: 1968-2012 Observation Band: 1987-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 48.2-L0 2nd: 38.6-R0.5 3rd: 34.8-R1



Schedule E

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500BRKX 500kV Breakers

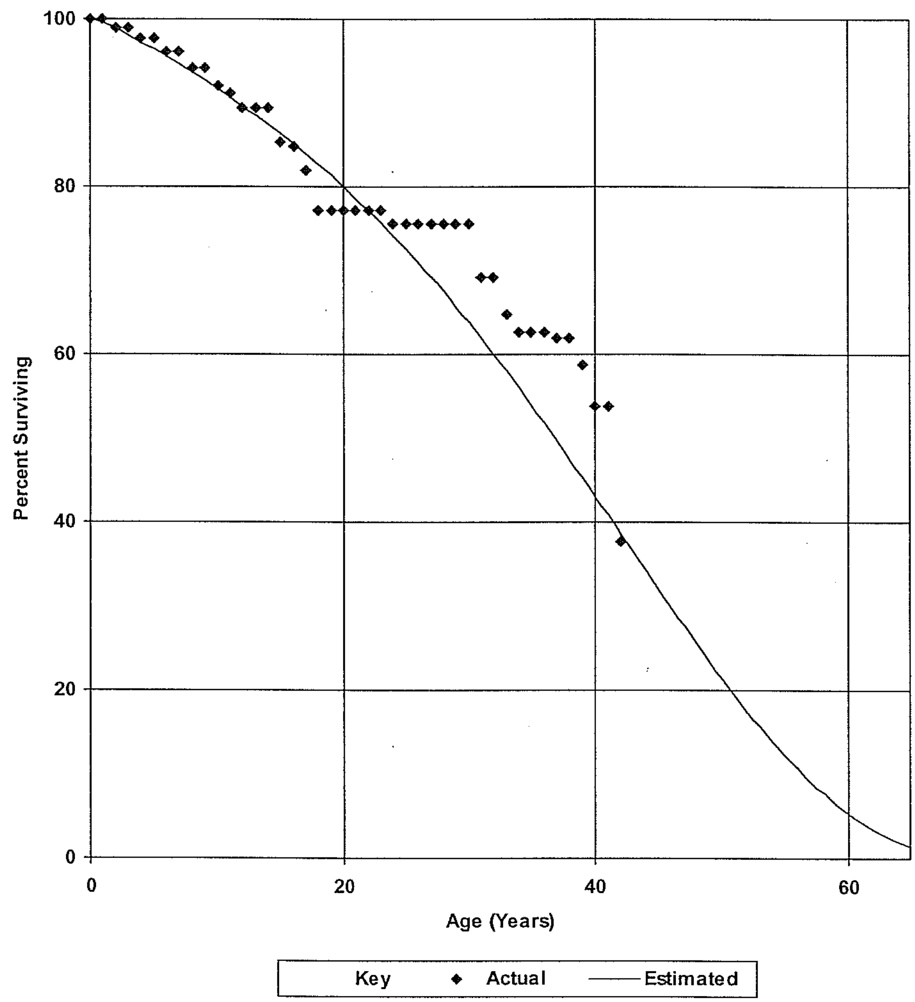
T-Cut: None

Placement Band: 1968-2012

Observation Band: 1987-2013

35.0-R1

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONA 500kV Conventional Air Breakers

Placement Band: 1968 - 1979
Observation Band: 1987 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	0	0	0.00000	1.00000	1.00000
0.5	0	0	0.00000	1.00000	1.00000
1.5	0	0	0.00000	1.00000	1.00000
2.5	0	0	0.00000	1.00000	1.00000
3.5	0	0	0.00000	1.00000	1.00000
4.5	0	0	0.00000	1.00000	1.00000
5.5	0	0	0.00000	1.00000	1.00000
6.5	0	0	0.00000	1.00000	1.00000
7.5	25	0	0.00000	1.00000	1.00000
8.5	25	0	0.00000	1.00000	1.00000
9.5	36	1	0.02778	0.97222	1.00000
10.5	35	2	0.05714	0.94286	0.97222
11.5	33	0	0.00000	1.00000	0.91667
12.5	33	0	0.00000	1.00000	0.91667
13.5	61	1	0.01639	0.98361	0.91667
14.5	70	0	0.00000	1.00000	0.90164
15.5	70	0	0.00000	1.00000	0.90164
16.5	70	0	0.00000	1.00000	0.90164
17.5	70	0	0.00000	1.00000	0.90164
18.5	73	0	0.00000	1.00000	0.90164
19.5	73	0	0.00000	1.00000	0.90164
20.5	73	0	0.00000	1.00000	0.90164
21.5	73	0	0.00000	1.00000	0.90164
22.5	73	3	0.04110	0.95890	0.90164
23.5	70	0	0.00000	1.00000	0.86459
24.5	70	0	0.00000	1.00000	0.86459
25.5	70	0	0.00000	1.00000	0.86459
26.5	70	0	0.00000	1.00000	0.86459
27.5	70	0	0.00000	1.00000	0.86459
28.5	70	0	0.00000	1.00000	0.86459
29.5	70	4	0.05714	0.94286	0.86459
30.5	66	0	0.00000	1.00000	0.81518
31.5	66	1	0.01515	0.98485	0.81518
32.5	65	4	0.06154	0.93846	0.80283
33.5	61	0	0.00000	1.00000	0.75342
34.5	45	0	0.00000	1.00000	0.75342
35.5	45	1	0.02222	0.97778	0.75342

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONA 500kV Conventional Air Breakers

Placement Band: 1968 - 1979
Observation Band: 1987 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	38	0	0.00000	1.00000	0.73668
37.5	38	2	0.05263	0.94737	0.73668
38.5	36	3	0.08333	0.91667	0.69791
39.5	33	0	0.00000	1.00000	0.63975
40.5	10	3	0.30000	0.70000	0.63975
41.5	0	0	0.00000	1.00000	0.44783

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONA 500kV Conventional Air Breakers

T-Cut: None
Placement Band: 1968-1979
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-1991	89.3	136.8	SC*	19.38	165.5	R1*	5.41	26.4	R4*	1.92
1988-1992	84.9	140.5	SC*	16.59	153.6	R0.5*	10.29	28.6	R4*	3.11
1989-1993	89.2	124.1	SC*	25.15	22.4	O3*	38.24	25.3	R0.5*	20.61
1990-1994	89.2	106.2	O4*	32.96	9.4	O4*	65.25	2.2	O4*	88.88
1991-1995	97.0	163.3	R1*	13.17	46.1	R0.5*	19.31	36.1	R5*	1.19
1992-1996	92.1	39.7	L3*	3.31	33.7	R3*	6.16	1.7	O4*	93.99
1993-1997	92.1	43.1	L3*	2.69	160.6	R1*	2.50	2.2	O4*	93.47
1994-1998	92.1	47.9	L3*	2.29	179.1	R3*	1.83	20.4	O4*	82.19
1995-1999	92.1	55.9	L2*	2.49	180.5	R3*	1.62	180.5	R3*	1.60
1996-2000	91.9	80.8	O2	10.02	180.6	R3*	1.46	41.0	R5*	1.76
1997-2001	100.0				No Retirements					
1998-2002	100.0				No Retirements					
1999-2003	100.0				No Retirements					
2000-2004	100.0				No Retirements					
2001-2005	100.0				No Retirements					
2002-2006	33.3	46.6	L4*	8.52	0.4	S3*	97.09	37.2	S6*	9.08
2003-2007	0.0	44.2	S4*	13.52	0.3	SC*	96.41	36.9	S6*	9.66
2004-2008	0.0	45.5	S4*	14.10	0.3	SC*	96.41	37.3	S6*	8.06
2005-2009	0.0	46.7	L4*	13.58	0.3	S1*	93.69	36.9	R5*	6.62
2006-2010	0.0	46.9	L3*	10.92	0.7	O2	92.78	37.6	R5*	7.75
2007-2011	59.7	15.8	O4*	74.50	126.3	SC*	10.20	39.2	R5*	4.09
2008-2012	64.0	5.0	O4*	83.36	1.3	O3	89.67	39.3	R5*	1.64
2009-2013	43.4	5.2	O4*	81.59	0.3	SC	91.03	36.0	S3*	10.81

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONA 500kV Conventional Air Breakers

T-Cut: None

Placement Band: 1968-1979

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-2013	44.8	49.8	L2 *	5.24	29.9	SC	23.55	37.5	R2	5.42
1989-2013	44.3	49.4	S1.5 *	6.22	26.1	SC	30.87	34.4	R1	11.45
1991-2013	48.2	48.5	L3 *	3.26	28.3	SC	31.68	41.6	R4 *	2.31
1993-2013	49.6	48.0	L3 *	3.12	28.5	SC	33.10	41.7	R4 *	2.44
1995-2013	49.6	47.7	L3 *	3.00	22.6	O3	45.51	41.3	R4 *	2.49
1997-2013	51.8	47.3	S3 *	3.10	20.7	O4 *	50.95	42.3	R5 *	2.45
1999-2013	51.7	46.9	L4 *	2.87	16.8	O4	59.32	41.9	R5 *	2.50
2001-2013	51.6	46.6	L4 *	2.76	12.2	O4	68.94	41.3	R5 *	2.72
2003-2013	50.9	46.2	L4 *	2.66	6.8	O4	80.19	40.6	R5 *	2.90
2005-2013	47.7	45.7	L4 *	2.93	2.2	O3	88.60	39.9	R5 *	2.05
2007-2013	45.0	38.7	L1 *	18.43	0.6	O3	91.04	39.3	R5 *	1.81
2009-2013	43.4	5.2	O4 *	81.59	0.3	SC	91.03	36.0	S3 *	10.81
2011-2013	47.6	38.9	S1.5 *	16.88	0.3	SC *	93.69	40.4	S6 *	2.80
2013-2013	60.0	43.1	S5 *	3.76	0.3	SC *	96.49	39.9	S6 *	6.15

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONA 500kV Conventional Air Breakers

T-Cut: None
Placement Band: 1968-1979
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-1988	90.9	161.0	R1 *	10.35	182.3	R4 *	1.68	23.4	R4 *	1.96
1987-1990	91.7	138.1	SC *	20.31	164.5	R1 *	7.50	25.0	R4 *	3.17
1987-1992	89.3	140.2	SC *	18.09	154.5	R0.5 *	11.02	27.9	R4 *	1.33
1987-1994	90.2	145.1	SC *	16.44	60.4	R0.5 *	17.63	30.5	R4 *	1.81
1987-1996	83.6	80.8	O2	5.52	23.1	SC	27.63	25.8	R1	16.12
1987-1998	83.6	151.8	SC *	7.10	30.3	SC	19.70	104.5	O4 *	27.03
1987-2000	84.8	155.4	R0.5 *	8.12	37.6	SC	15.85	115.6	SC *	27.50
1987-2002	86.5	155.9	R0.5 *	8.87	44.8	R0.5	14.27	121.5	SC *	25.56
1987-2004	86.5	156.2	R0.5 *	8.85	50.9	R0.5	13.19	127.5	SC *	22.79
1987-2006	28.8	112.7	SC	8.61	28.7	SC *	28.49	36.6	R4 *	7.04
1987-2008	0.0	88.9	L0	14.81	28.6	SC *	29.72	37.4	R4 *	10.75
1987-2010	0.0	60.4	L1.5 *	11.93	32.5	SC	22.05	37.4	R2	11.53
1987-2012	65.4	54.0	L2 *	4.01	33.6	SC	18.43	33.8	SC	17.85
1987-2013	44.8	49.8	L2 *	5.24	29.9	SC	23.55	37.5	R2	5.42

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONA 500kV Conventional Air Breakers

T-Cut: None

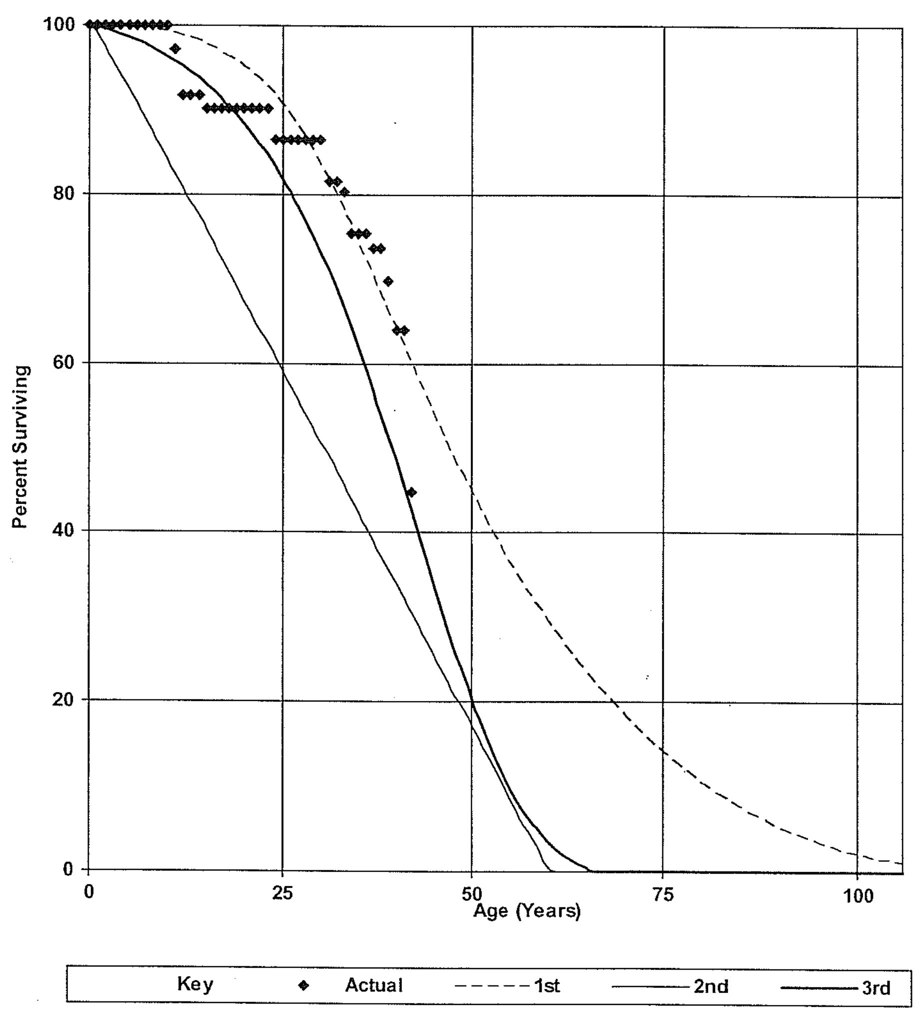
Placement Band: 1968-1979 Observation Band: 1987-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 49.8-L2 2nd: 29.9-SC 3rd: 37.5-R2



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONA 500kV Conventional Air Breakers

T-Cut: None

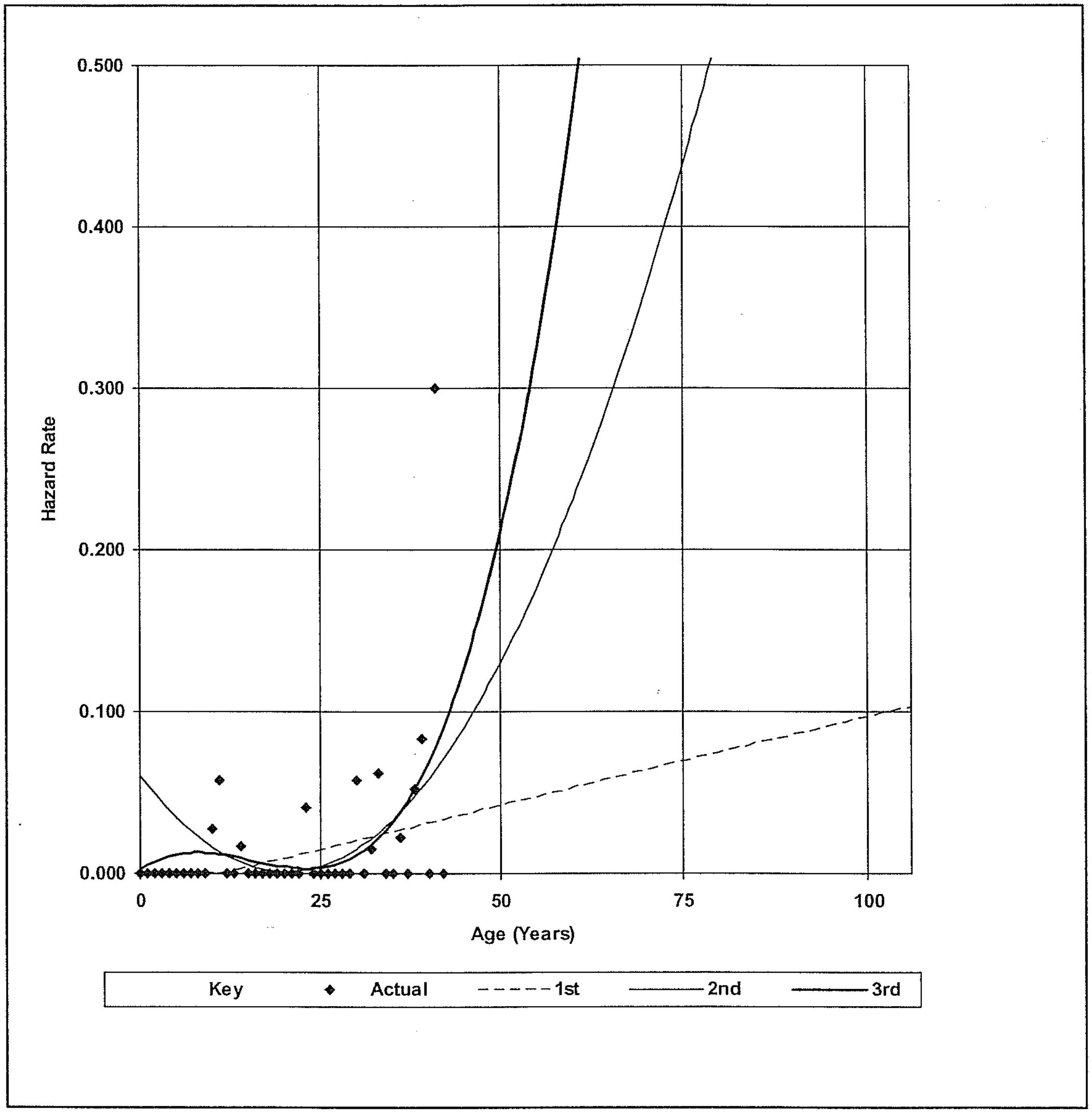
Placement Band: 1968-1979 Observation Band: 1987-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 49.8-L2 2nd: 29.9-SC 3rd: 37.5-R2



Schedule E

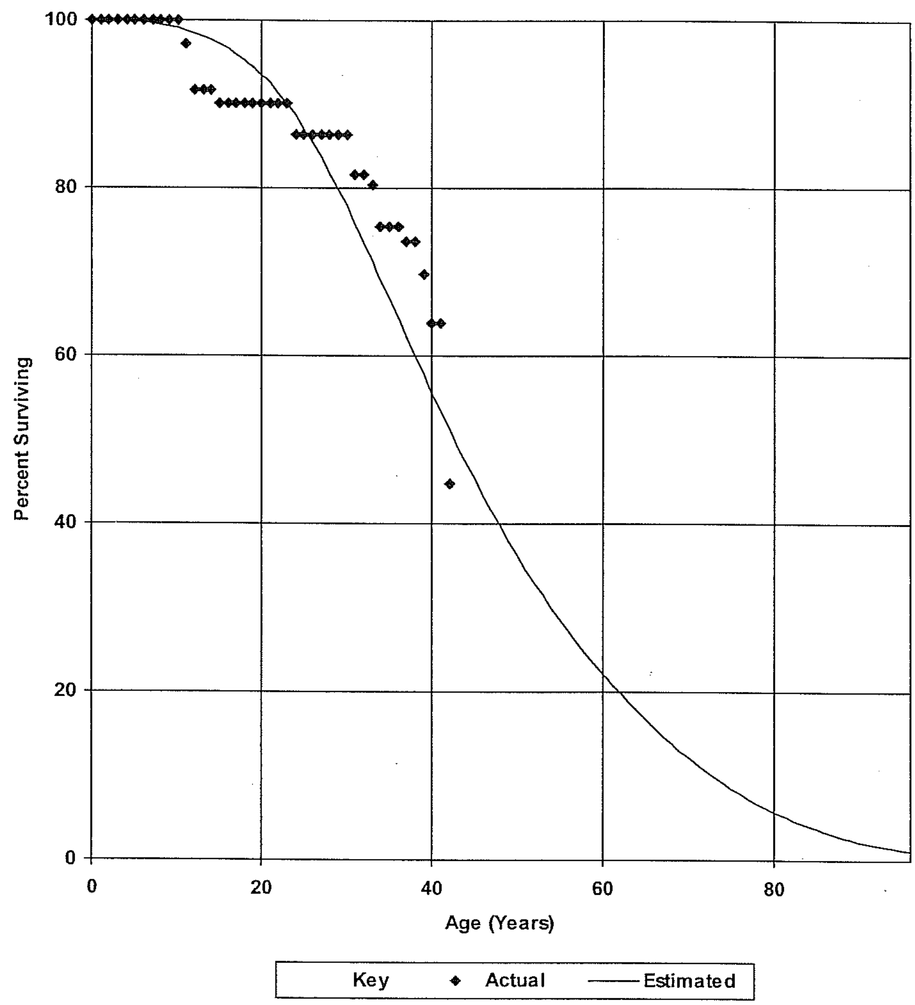
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONA 500kV Conventional Air Breakers

T-Cut: None
Placement Band: 1968-1979
Observation Band: 1987-2013
45.0-L2

Estimated Projection Life Curve



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONS 500kV Conventional and GIS SF6 Breakers

Placement Band: 1977 - 2012
Observation Band: 1992 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	75	0	0.00000	1.00000	1.00000
0.5	90	1	0.01111	0.98889	1.00000
1.5	88	0	0.00000	1.00000	0.98889
2.5	88	1	0.01136	0.98864	0.98889
3.5	96	0	0.00000	1.00000	0.97765
4.5	58	1	0.01724	0.98276	0.97765
5.5	41	0	0.00000	1.00000	0.96080
6.5	45	1	0.02222	0.97778	0.96080
7.5	44	0	0.00000	1.00000	0.93944
8.5	64	2	0.03125	0.96875	0.93944
9.5	60	0	0.00000	1.00000	0.91009
10.5	60	0	0.00000	1.00000	0.91009
11.5	60	0	0.00000	1.00000	0.91009
12.5	60	0	0.00000	1.00000	0.91009
13.5	93	6	0.06452	0.93548	0.91009
14.5	87	1	0.01149	0.98851	0.85137
15.5	102	6	0.05882	0.94118	0.84159
16.5	150	13	0.08667	0.91333	0.79208
17.5	134	0	0.00000	1.00000	0.72343
18.5	134	0	0.00000	1.00000	0.72343
19.5	134	0	0.00000	1.00000	0.72343
20.5	116	0	0.00000	1.00000	0.72343
21.5	114	0	0.00000	1.00000	0.72343
22.5	113	1	0.00885	0.99115	0.72343
23.5	110	0	0.00000	1.00000	0.71703
24.5	110	0	0.00000	1.00000	0.71703
25.5	100	0	0.00000	1.00000	0.71703
26.5	100	0	0.00000	1.00000	0.71703
27.5	100	0	0.00000	1.00000	0.71703
28.5	79	0	0.00000	1.00000	0.71703
29.5	79	9	0.11392	0.88608	0.71703
30.5	70	0	0.00000	1.00000	0.63534
31.5	70	8	0.11429	0.88571	0.63534
32.5	62	0	0.00000	1.00000	0.56273
33.5	44	0	0.00000	1.00000	0.56273
34.5	44	0	0.00000	1.00000	0.56273
35.5	36	0	0.00000	1.00000	0.56273

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONS 500kV Conventional and GIS SF6 Breakers

Placement Band: 1977 - 2012
Observation Band: 1992 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	0	0	0.00000	1.00000	0.56273

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONS 500kV Conventional and GIS SF6 Breakers

T-Cut: None
Placement Band: 1977-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1992-1996	45.9	17.3	L1	7.31	61.8	O4 *	12.55	72.0	O4 *	11.06
1993-1997	54.4	20.2	L0.5	8.83	82.4	O4 *	13.60	88.9	O4 *	10.01
1994-1998	57.6	23.3	L0.5	9.52	96.4	O4 *	12.97	103.1	O4 *	7.71
1995-1999	100.0				No Retirements					
1996-2000	100.0				No Retirements					
1997-2001	100.0				No Retirements					
1998-2002	100.0				No Retirements					
1999-2003	97.0	188.8	R5 *	2.23	190.7	R5 *	0.95	53.2	R4 *	1.14
2000-2004	97.0	187.3	R4 *	2.89	190.5	R5 *	0.97	46.5	R4 *	1.26
2001-2005	92.9	185.6	R4 *	2.61	190.2	R5 *	2.26	50.0	R4 *	2.08
2002-2006	93.3	183.7	R4 *	2.99	189.4	R5 *	1.80	51.3	R4 *	1.69
2003-2007	94.1	181.7	R4 *	3.78	187.7	R4 *	1.29	51.2	R4 *	1.16
2004-2008	100.0				No Retirements					
2005-2009	81.2	55.7	L2 *	4.82	30.2	R0.5 *	20.24	26.5	R0.5 *	24.36
2006-2010	73.6	38.7	L2 *	12.13	34.9	R3 *	7.09	31.9	R3 *	11.27
2007-2011	71.4	38.1	L2 *	13.50	37.1	S3 *	4.93	88.0	O4 *	6.12
2008-2012	62.7	37.1	L1 *	14.52	36.1	R2	8.41	118.1	SC *	7.35
2009-2013	50.5	36.3	L1	12.09	35.9	L1	11.55	110.5	O4 *	6.30

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONS 500kV Conventional and GIS SF6 Breakers

T-Cut: None
Placement Band: 1977-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1992-2013	56.3	46.7	O2	4.02	96.4	O4 *	3.60	33.1	R1 *	4.09
1994-2013	58.5	46.3	O2	4.96	99.4	O4 *	4.41	34.0	R1 *	5.19
1996-2013	73.6	55.5	L1.5 *	3.44	43.0	R3 *	2.50	91.0	O4 *	2.60
1998-2013	72.9	54.8	L1.5 *	3.46	42.8	R2.5 *	2.51	97.2	O4 *	2.56
2000-2013	72.8	53.7	L1.5 *	3.74	42.5	R2.5	2.57	104.7	O4 *	2.60
2002-2013	71.6	51.9	L1.5 *	4.03	42.1	R2.5	2.67	117.5	O3 *	2.53
2004-2013	71.8	49.7	L1.5 *	5.36	41.9	R2.5	2.91	135.1	SC *	2.53
2006-2013	71.0	45.6	L1	7.98	40.7	R2	5.03	136.0	SC *	3.57
2008-2013	60.4	39.8	L1	11.21	38.1	S0.5	9.35	123.3	SC *	5.77
2010-2013	53.6	40.1	L0.5	10.56	91.0	O4 *	15.22	113.4	O3 *	7.32
2012-2013	73.3	159.7	R1 *	7.77	152.1	SC *	6.18	39.9	R1 *	7.57

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONS 500kV Conventional and GIS SF6 Breakers

T-Cut: None
Placement Band: 1977-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1992-1993	69.2	10.2	L2*	4.47	10.2	L2*	4.47	113.8	SC*	9.75
1992-1995	33.2	14.7	L1.5*	11.45	24.2	O4*	14.83	53.5	O4*	13.88
1992-1997	51.4	19.8	L0.5	7.02	80.5	O4*	11.65	86.5	O4*	8.77
1992-1999	58.2	25.7	O2	8.03	101.8	O4*	9.56	107.4	O4*	5.76
1992-2001	63.1	35.4	O3	8.93	115.7	SC*	7.12	120.1	SC*	4.30
1992-2003	66.5	80.5	O4*	10.16	123.6	SC*	5.91	125.1	SC*	4.91
1992-2005	68.7	112.3	O3*	10.23	130.7	SC*	4.38	78.2	SC*	4.70
1992-2007	70.6	122.3	SC*	10.36	135.3	SC*	3.85	38.8	R0.5*	4.82
1992-2009	60.6	97.0	O4*	7.14	121.4	SC*	5.71	28.9	R1*	6.40
1992-2011	54.1	41.5	L0	4.28	37.2	S-.5	4.37	29.5	R1*	5.82
1992-2013	56.3	46.7	O2	4.02	96.4	O4*	3.60	33.1	R1*	4.09

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONS 500kV Conventional and GIS SF6 Breakers

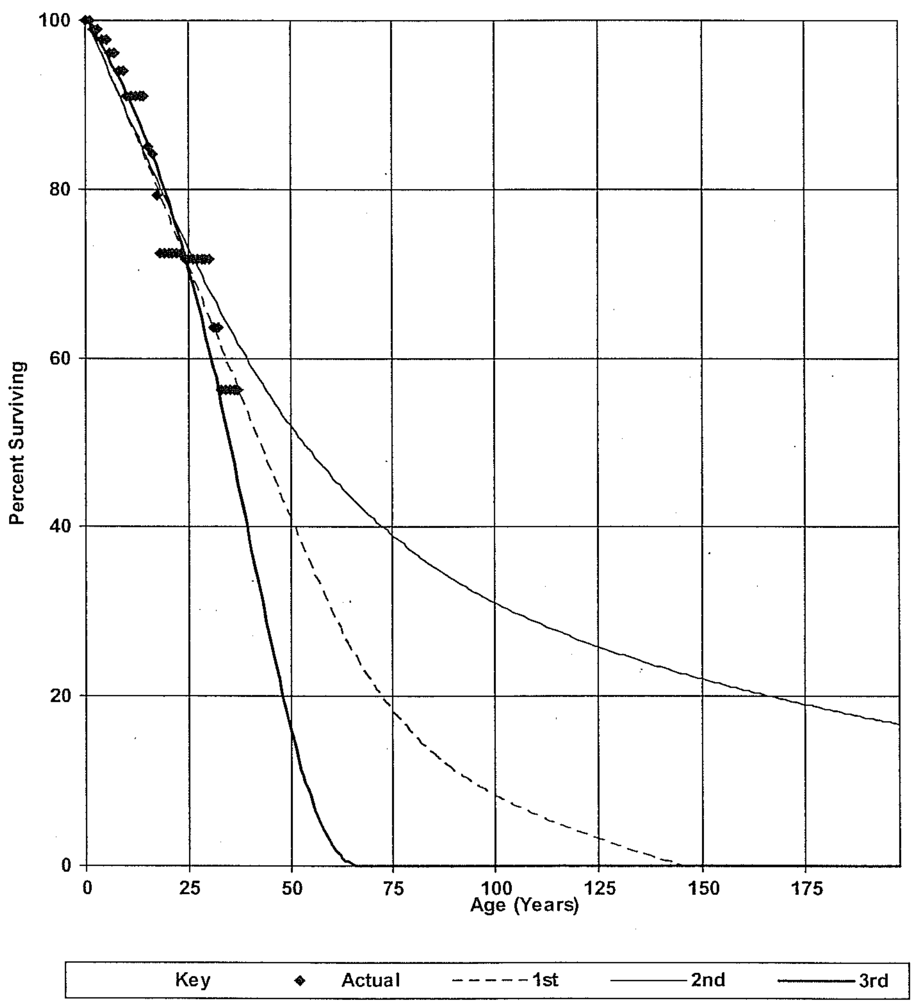
T-Cut: None

Placement Band: 1977-2012 Observation Band: 1992-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis 1st: 46.7-O2 2nd: 96.4-O4 3rd: 33.1-R1



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONS 500kV Conventional and GIS SF6 Breakers

T-Cut: None

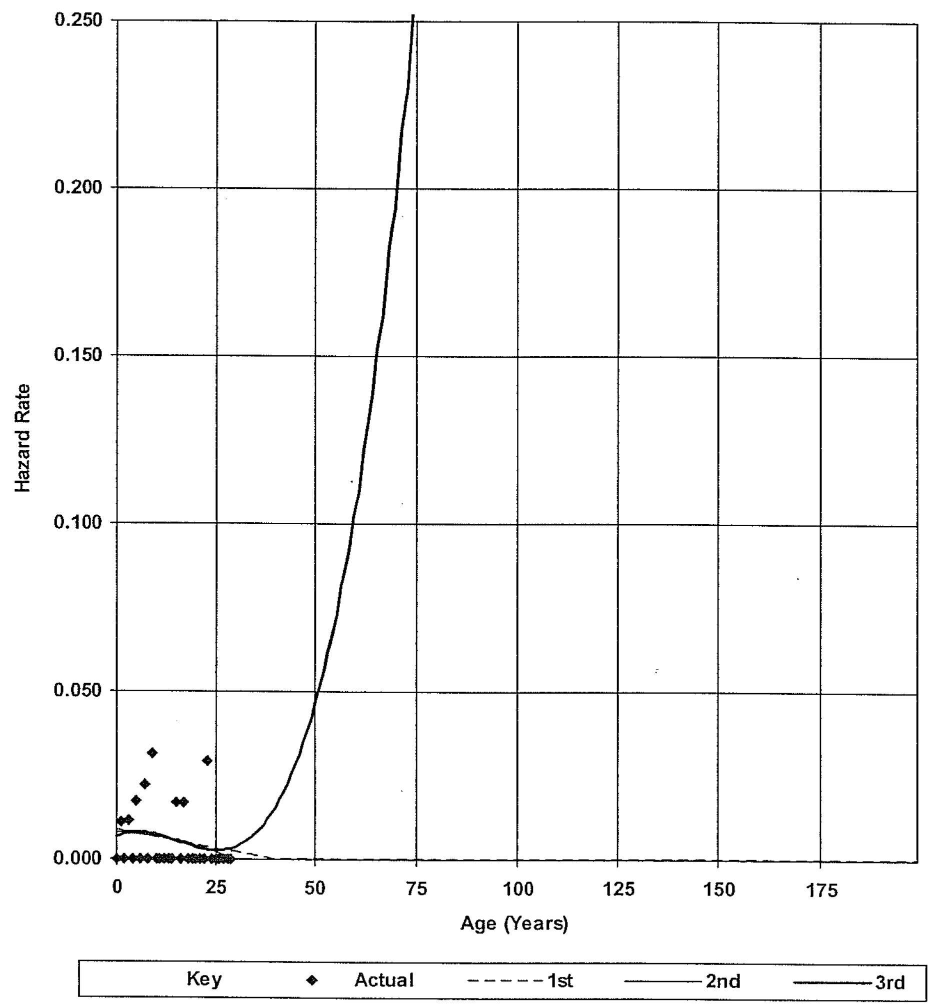
Placement Band: 1985-2012 Observation Band: 1992-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 168.8-R1.5 2nd: 171.7-R2 3rd: 48.7-R2.5



Schedule E

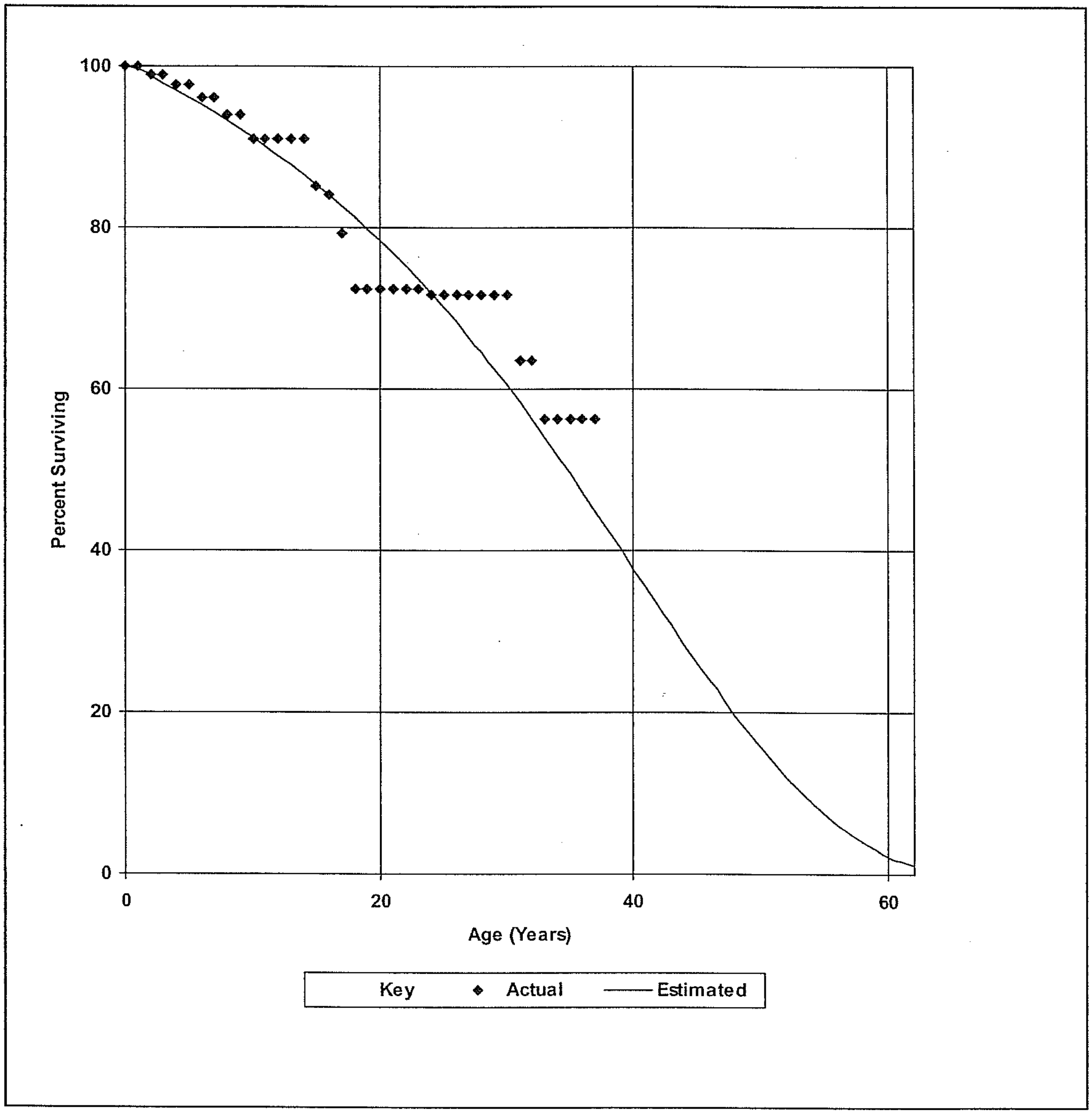
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: 500CONS 500kV Conventional and GIS SF6 Breakers

T-Cut: None
Placement Band: 1977-2012
Observation Band: 1992-2013
33.0-R1

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: AUTOTRN Auto Transformers

Placement Band: 1948 - 2012
Observation Band: 1983 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	51	0	0.00000	1.00000	1.00000
0.5	54	0	0.00000	1.00000	1.00000
1.5	55	1	0.01818	0.98182	1.00000
2.5	56	0	0.00000	1.00000	0.98182
3.5	54	1	0.01852	0.98148	0.98182
4.5	53	0	0.00000	1.00000	0.96364
5.5	56	0	0.00000	1.00000	0.96364
6.5	60	0	0.00000	1.00000	0.96364
7.5	59	0	0.00000	1.00000	0.96364
8.5	67	0	0.00000	1.00000	0.96364
9.5	64	0	0.00000	1.00000	0.96364
10.5	75	0	0.00000	1.00000	0.96364
11.5	79	0	0.00000	1.00000	0.96364
12.5	78	1	0.01282	0.98718	0.96364
13.5	88	0	0.00000	1.00000	0.95128
14.5	98	1	0.01020	0.98980	0.95128
15.5	102	2	0.01961	0.98039	0.94158
16.5	102	1	0.00980	0.99020	0.92311
17.5	104	1	0.00962	0.99038	0.91406
18.5	103	1	0.00971	0.99029	0.90527
19.5	105	0	0.00000	1.00000	0.89648
20.5	104	0	0.00000	1.00000	0.89648
21.5	101	0	0.00000	1.00000	0.89648
22.5	104	1	0.00962	0.99038	0.89648
23.5	96	0	0.00000	1.00000	0.88786
24.5	99	1	0.01010	0.98990	0.88786
25.5	99	0	0.00000	1.00000	0.87890
26.5	105	0	0.00000	1.00000	0.87890
27.5	105	3	0.02857	0.97143	0.87890
28.5	102	0	0.00000	1.00000	0.85378
29.5	105	1	0.00952	0.99048	0.85378
30.5	102	0	0.00000	1.00000	0.84565
31.5	109	1	0.00917	0.99083	0.84565
32.5	107	1	0.00935	0.99065	0.83790
33.5	104	4	0.03846	0.96154	0.83006
34.5	109	2	0.01835	0.98165	0.79814
35.5	107	0	0.00000	1.00000	0.78349

Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: AUTOTRN Auto Transformers

Placement Band: 1948 - 2012
Observation Band: 1983 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	103	3	0.02913	0.97087	0.78349
37.5	94	1	0.01064	0.98936	0.76067
38.5	93	1	0.01075	0.98925	0.75258
39.5	85	4	0.04706	0.95294	0.74449
40.5	79	1	0.01266	0.98734	0.70945
41.5	70	1	0.01429	0.98571	0.70047
42.5	65	0	0.00000	1.00000	0.69047
43.5	65	1	0.01538	0.98462	0.69047
44.5	55	0	0.00000	1.00000	0.67984
45.5	46	0	0.00000	1.00000	0.67984
46.5	41	0	0.00000	1.00000	0.67984
47.5	39	0	0.00000	1.00000	0.67984
48.5	36	0	0.00000	1.00000	0.67984
49.5	36	1	0.02778	0.97222	0.67984
50.5	33	0	0.00000	1.00000	0.66096
51.5	33	1	0.03030	0.96970	0.66096
52.5	32	1	0.03125	0.96875	0.64093
53.5	28	0	0.00000	1.00000	0.62090
54.5	26	0	0.00000	1.00000	0.62090
55.5	21	0	0.00000	1.00000	0.62090
56.5	21	0	0.00000	1.00000	0.62090
57.5	18	0	0.00000	1.00000	0.62090
58.5	17	0	0.00000	1.00000	0.62090
59.5	17	0	0.00000	1.00000	0.62090
60.5	14	0	0.00000	1.00000	0.62090
61.5	14	0	0.00000	1.00000	0.62090
62.5	8	1	0.12500	0.87500	0.62090
63.5	5	0	0.00000	1.00000	0.54329
64.5	5	0	0.00000	1.00000	0.54329
65.5	0	0	0.00000	1.00000	0.54329

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: AUTOTRN Auto Transformers

T-Cut: None

Placement Band: 1948-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1983-1987	65.4	59.5	L0	2.67	56.2	L0.5	2.66	132.5	SC *	3.35
1984-1988	69.0	60.4	O2	4.61	107.5	O3 *	4.20	124.5	SC *	6.94
1985-1989	77.8	68.1	L1	3.17	150.7	SC *	2.64	154.5	SC *	2.65
1986-1990	70.3	67.5	L1	3.15	118.1	SC *	2.87	48.9	R2.5 *	3.18
1987-1991	47.2	44.4	L2 *	3.13	42.2	S1.5	3.14	40.6	R2.5 *	3.54
1988-1992	38.9	41.9	L2 *	3.20	40.2	S1.5	2.81	38.8	R2 *	3.65
1989-1993	40.2	41.8	L2 *	7.60	41.6	S2 *	4.44	42.5	L3 *	4.71
1990-1994	42.2	42.4	L2 *	7.71	42.1	S2 *	5.11	75.4	O4 *	5.85
1991-1995	46.3	45.7	L2 *	6.87	44.9	S1.5 *	5.66	98.4	O4 *	6.58
1992-1996	69.2	64.5	L2 *	3.66	62.4	L2 *	3.61	142.5	SC *	3.47
1993-1997	72.9	82.3	L1.5 *	7.23	144.7	SC *	6.88	155.2	R0.5 *	5.06
1994-1998	83.3	134.9	S0.5 *	6.81	185.9	R4 *	6.46	183.1	R4 *	5.21
1995-1999	41.7	172.5	R2 *	41.15	71.9	R2	38.94	145.6	SC *	30.86
1996-2000	0.0	170.8	R1.5 *	85.99	70.2	R1.5 *	82.76	134.0	SC *	71.05
1997-2001	0.0	169.0	R1.5 *	85.21	68.7	R1.5 *	81.00	124.7	SC *	66.47
1998-2002	50.0	173.1	R2 *	37.68	64.9	R1 *	30.07	127.0	SC *	17.51
1999-2003	59.1	156.1	R0.5 *	19.06	48.5	SC *	6.62	106.4	O4 *	6.50
2000-2004	88.7	139.5	R0.5	3.51	69.4	R2 *	9.12	63.9	R3 *	5.65
2001-2005	84.4	131.1	SC	5.93	77.0	R1.5	8.33	65.2	R2.5	6.50
2002-2006	72.2	89.1	L0.5	6.29	71.0	R1	7.74	64.0	R1.5	7.29
2003-2007	66.8	96.7	O3	8.82	74.6	SC	9.25	57.4	R1	8.99
2004-2008	76.2	108.9	SC	8.76	147.7	SC *	6.15	88.3	R1 *	6.67
2005-2009	62.5	77.1	L0	6.90	127.5	SC *	5.34	130.9	SC *	4.96
2006-2010	69.1	84.2	L0	7.26	131.7	SC *	6.36	138.8	SC *	5.83
2007-2011	63.0	81.5	L1	5.69	72.8	S0.5	6.08	61.6	R1.5 *	8.24
2008-2012	59.8	71.0	L1 *	8.13	109.7	O3 *	8.81	122.4	SC *	7.76
2009-2013	63.2	71.6	L1 *	8.67	114.5	O3 *	9.52	126.4	SC *	7.71

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: AUTOTRN Auto Transformers

T-Cut: None

Placement Band: 1948-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1983-2013	54.3	73.4	L0	2.46	113.2	O3 *	1.91	127.2	SC *	1.94
1985-2013	56.2	74.0	L0.5	2.76	116.8	SC *	2.09	130.8	SC *	2.13
1987-2013	56.0	74.5	L0.5	2.62	117.5	SC *	1.98	131.3	SC *	1.95
1989-2013	56.7	75.4	L0.5	2.59	112.6	O3 *	2.21	133.0	SC *	2.08
1991-2013	56.7	75.9	L0.5	2.63	115.9	O3 *	2.27	133.7	SC *	2.10
1993-2013	62.0	89.9	L0.5	2.15	87.7	L1	2.14	142.3	SC *	1.97
1995-2013	61.9	93.0	L0.5	2.33	82.3	S0	2.04	139.6	SC *	1.87
1997-2013	60.9	90.4	L0	2.03	81.7	S-.5	1.95	136.1	SC *	1.88
1999-2013	60.3	89.6	L0	2.14	78.0	R0.5	2.27	132.0	SC *	2.32
2001-2013	60.9	83.3	L0.5	2.90	117.9	SC *	2.31	104.4	O2 *	2.33
2003-2013	57.5	77.5	L0	3.96	117.8	SC *	2.99	101.3	O3 *	3.04
2005-2013	58.4	75.5	L0.5	6.11	125.4	SC *	4.88	125.9	SC *	4.83
2007-2013	61.9	76.7	L0.5	7.40	125.0	SC *	6.55	121.9	SC *	6.76
2009-2013	63.2	71.6	L1 *	8.67	114.5	O3 *	9.52	126.4	SC *	7.71
2011-2013	59.1	63.9	L0.5	12.38	107.7	O3 *	12.06	89.1	O3 *	12.73
2013-2013	0.0	103.3	O2	47.21	141.3	SC *	45.06	144.1	SC *	46.04

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: AUTOTRN Auto Transformers

T-Cut: None

Placement Band: 1948-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1983-1984	50.6	62.3	O3	13.58	114.2	O3 *	14.79	109.6	O4 *	10.74
1983-1986	63.9	59.1	L0	3.01	47.3	R0.5	2.65	122.3	SC *	2.87
1983-1988	66.6	58.8	L0	2.79	126.1	SC *	3.37	130.2	SC *	3.68
1983-1990	59.2	60.4	L0	2.88	57.2	L0.5	2.87	49.2	R1	3.14
1983-1992	40.5	45.6	L1.5 *	4.05	40.8	R1.5	2.21	39.7	R2 *	2.99
1983-1994	47.1	48.0	L1.5 *	2.28	44.1	S1	1.80	44.5	S1	1.83
1983-1996	55.2	52.8	L1.5 *	1.95	49.4	S0.5	1.78	105.4	O4 *	1.99
1983-1998	57.8	56.6	L1.5 *	2.14	56.0	L1.5 *	2.13	123.4	SC *	1.86
1983-2000	60.1	62.2	L0.5	2.52	61.0	L1	2.51	127.8	SC *	1.76
1983-2002	63.3	68.7	L0.5	2.37	93.4	O3 *	2.55	133.5	SC *	1.59
1983-2004	60.4	71.6	L0.5	1.94	72.1	L0.5	2.01	131.7	SC *	1.42
1983-2006	60.1	71.5	L0.5	1.55	85.8	O2 *	1.62	130.7	SC *	1.26
1983-2008	62.6	76.0	L0	2.04	123.1	SC *	1.47	133.5	SC *	1.40
1983-2010	61.8	76.5	L0	1.99	118.4	SC *	1.45	132.5	SC *	1.47
1983-2012	51.5	72.2	L0.5	2.43	101.4	O3 *	2.06	124.9	SC *	2.12
1983-2013	54.3	73.4	L0	2.46	113.2	O3 *	1.91	127.2	SC *	1.94

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: AUTOTRN Auto Transformers

T-Cut: None

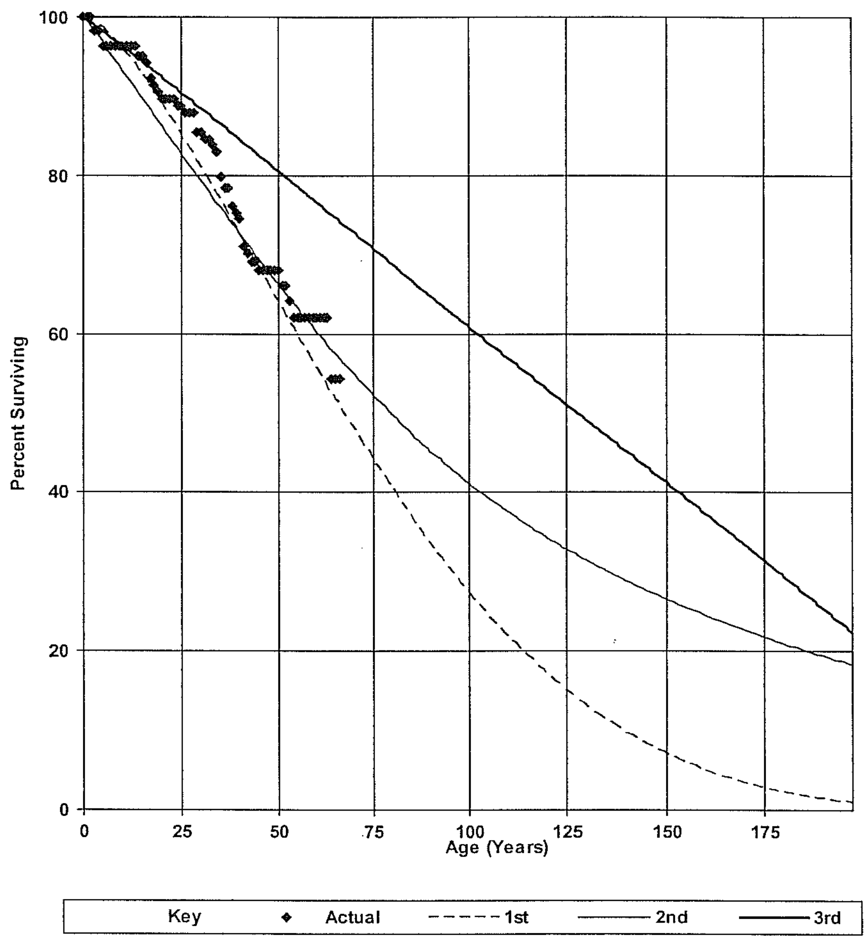
Placement Band: 1948-2012 Observation Band: 1983-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 73.4-L0 2nd: 113.2-O3 3rd: 127.2-SC



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: AUTOTRN Auto Transformers

T-Cut: None

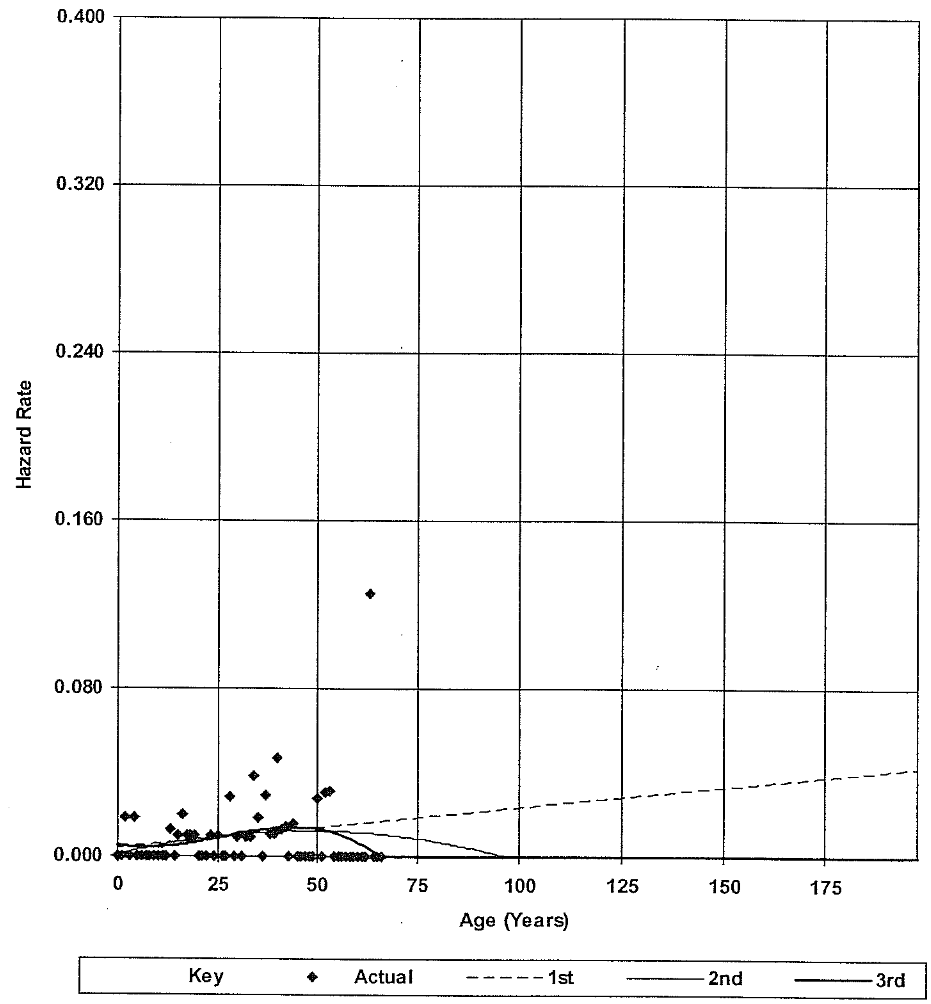
Placement Band: 1948-2013 Observation Band: 1983-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 73.4-L0 2nd: 113.2-O3 3rd: 127.2-SC



Schedule E

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: AUTOTRN Auto Transformers

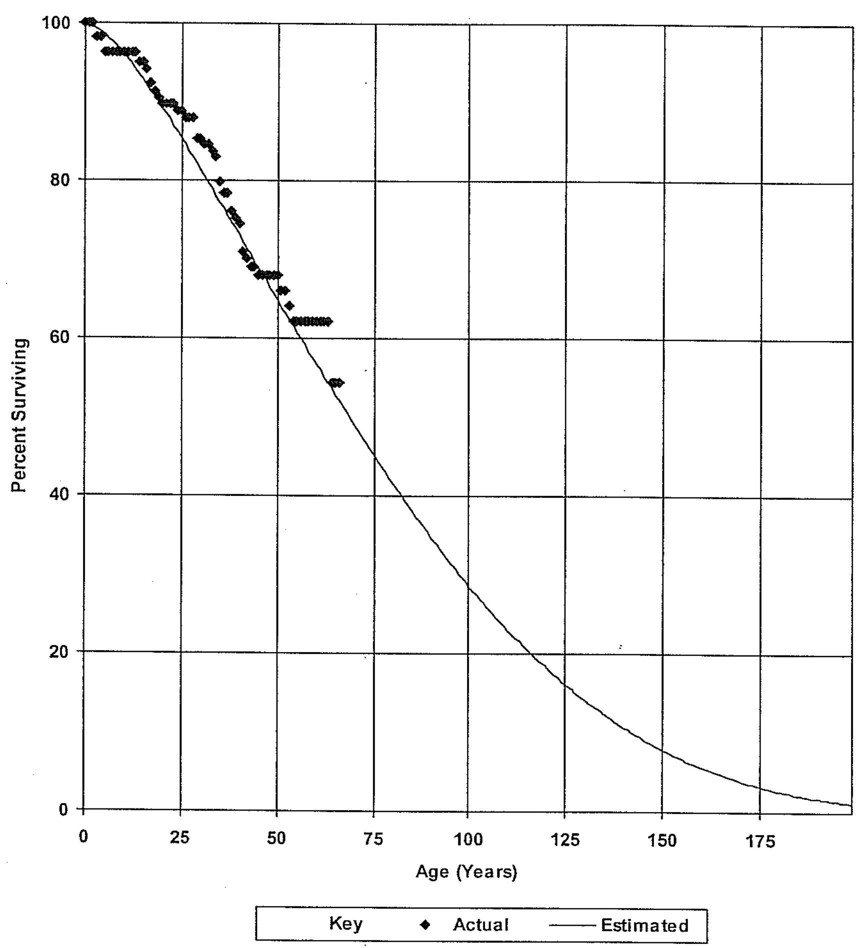
T-Cut: None

Placement Band: 1948-2012

Observation Band: 1983-2013

75.0-L0

Estimated Projection Life Curve



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: CAPACIT Capacitors

Placement Band: 1960 - 2012
Observation Band: 1988 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	358	0	0.00000	1.00000	1.00000
0.5	374	1	0.00267	0.99733	1.00000
1.5	365	1	0.00274	0.99726	0.99733
2.5	357	4	0.01120	0.98880	0.99459
3.5	353	0	0.00000	1.00000	0.98345
4.5	349	3	0.00860	0.99140	0.98345
5.5	336	4	0.01190	0.98810	0.97500
6.5	319	1	0.00313	0.99687	0.96339
7.5	312	2	0.00641	0.99359	0.96037
8.5	313	3	0.00958	0.99042	0.95421
9.5	304	3	0.00987	0.99013	0.94507
10.5	296	4	0.01351	0.98649	0.93574
11.5	281	1	0.00356	0.99644	0.92310
12.5	271	3	0.01107	0.98893	0.91981
13.5	264	1	0.00379	0.99621	0.90963
14.5	259	4	0.01544	0.98456	0.90618
15.5	246	4	0.01626	0.98374	0.89219
16.5	213	4	0.01878	0.98122	0.87768
17.5	193	2	0.01036	0.98964	0.86120
18.5	196	1	0.00510	0.99490	0.85227
19.5	187	0	0.00000	1.00000	0.84793
20.5	162	0	0.00000	1.00000	0.84793
21.5	128	1	0.00781	0.99219	0.84793
22.5	102	6	0.05882	0.94118	0.84130
23.5	76	2	0.02632	0.97368	0.79181
24.5	70	1	0.01429	0.98571	0.77098
25.5	59	4	0.06780	0.93220	0.75996
26.5	44	1	0.02273	0.97727	0.70844
27.5	45	3	0.06667	0.93333	0.69234
28.5	42	2	0.04762	0.95238	0.64618
29.5	40	1	0.02500	0.97500	0.61541
30.5	38	0	0.00000	1.00000	0.60003
31.5	36	1	0.02778	0.97222	0.60003
32.5	33	0	0.00000	1.00000	0.58336
33.5	32	1	0.03125	0.96875	0.58336
34.5	28	0	0.00000	1.00000	0.56513
35.5	27	1	0.03704	0.96296	0.56513

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: CAPACIT Capacitors

Placement Band: 1960 - 2012
Observation Band: 1988 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	25	0	0.00000	1.00000	0.54420
37.5	25	0	0.00000	1.00000	0.54420
38.5	25	0	0.00000	1.00000	0.54420
39.5	25	0	0.00000	1.00000	0.54420
40.5	25	2	0.08000	0.92000	0.54420
41.5	23	1	0.04348	0.95652	0.50066
42.5	22	2	0.09091	0.90909	0.47889
43.5	20	0	0.00000	1.00000	0.43536
44.5	13	1	0.07692	0.92308	0.43536
45.5	10	0	0.00000	1.00000	0.40187
46.5	5	1	0.20000	0.80000	0.40187
47.5	4	0	0.00000	1.00000	0.32150
48.5	1	0	0.00000	1.00000	0.32150
49.5	1	0	0.00000	1.00000	0.32150
50.5	1	0	0.00000	1.00000	0.32150
51.5	1	0	0.00000	1.00000	0.32150
52.5	1	0	0.00000	1.00000	0.32150
53.5	0	0	0.00000	1.00000	0.32150

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: CAPACIT Capacitors

T-Cut: None

Placement Band: 1960-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-1992	50.0	61.7	L1.5*	14.36	38.8	S3 *	12.20	34.0	S4 *	10.30
1989-1993	100.0				No Retirements					
1990-1994	90.2	187.6	R4*	4.31	184.4	R4 *	3.00	49.3	R4 *	2.78
1991-1995	79.5	189.2	R5*	14.03	186.7	R4 *	12.84	54.5	R4 *	12.91
1992-1996	85.5	113.9	SC	4.66	175.4	R2.5 *	2.33	174.3	R2 *	2.17
1993-1997	87.5	123.2	SC	3.74	178.3	R3 *	1.99	176.4	R2.5 *	1.75
1994-1998	83.5	75.6	L1	2.20	166.9	R1 *	1.54	163.0	R1 *	2.53
1995-1999	75.0	77.6	L1.5*	8.51	172.8	R2 *	7.52	168.6	R1.5 *	5.62
1996-2000	29.1	50.1	L1.5*	25.83	137.4	SC *	23.93	130.7	SC *	20.88
1997-2001	0.0	53.6	L1	44.65	141.7	SC *	43.29	135.1	SC *	40.59
1998-2002	0.0	49.0	L1	42.03	131.4	SC *	40.53	121.4	SC *	36.78
1999-2003	57.0	58.2	L0.5	10.97	144.4	SC *	9.99	137.0	SC *	7.82
2000-2004	62.3	66.0	O2	5.70	138.3	SC *	5.23	131.8	SC *	4.49
2001-2005	39.2	68.5	O2	16.25	133.7	SC *	16.76	122.3	SC *	12.94
2002-2006	48.3	57.1	O2	8.12	126.1	SC *	8.56	111.7	O4 *	4.44
2003-2007	58.8	119.9	SC*	3.97	128.3	SC *	4.18	114.2	O3 *	4.33
2004-2008	55.8	114.5	O3*	2.93	119.2	SC *	2.78	110.8	O4 *	3.26
2005-2009	65.0	124.6	SC*	3.33	127.7	SC *	2.70	120.2	SC *	5.03
2006-2010	37.1	52.9	O3	3.45	39.9	SC	3.12	42.7	O2 *	3.15
2007-2011	29.6	42.3	O2	7.11	35.1	SC	6.05	69.1	O4 *	4.46
2008-2012	22.6	38.0	L1	9.33	34.6	R0.5	7.97	56.7	O4 *	5.67
2009-2013	6.4	36.3	L2*	15.52	34.7	S0.5	15.03	50.0	O4 *	9.44

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: CAPACIT Capacitors

T-Cut: None
Placement Band: 1960-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-2013	32.1	43.7	L1	2.98	41.8	S0	2.93	46.1	L1 *	2.84
1990-2013	32.6	43.9	L1	2.76	41.9	L1	2.73	42.5	L1 *	2.69
1992-2013	31.9	43.4	L1	2.92	41.6	L1	2.91	46.3	L0.5 *	2.83
1994-2013	30.5	42.8	L0.5	3.59	41.0	L1	3.58	58.8	O3 *	3.34
1996-2013	28.5	42.2	L1	4.85	40.6	L1	4.80	67.9	O4 *	4.31
1998-2013	25.6	41.4	L0.5	6.78	39.5	L1	6.66	71.4	O4 *	5.77
2000-2013	23.0	40.5	L0.5	7.97	38.1	S-.5	7.73	70.1	O4 *	6.48
2002-2013	22.1	40.4	L0.5	8.21	37.3	R0.5	7.68	69.9	O4 *	5.83
2004-2013	18.9	38.6	L0.5	8.95	35.3	R0.5	8.13	64.8	O4 *	5.71
2006-2013	15.8	38.5	L1	10.49	35.5	R0.5	9.35	62.6	O4 *	6.22
2008-2013	8.5	37.0	L1.5 *	13.97	34.6	S0	12.75	55.1	O4 *	8.91
2010-2013	3.5	33.8	L2 *	16.94	33.5	S1 *	17.49	41.1	O3 *	11.23
2012-2013	12.4	35.6	S1.5 *	7.40	35.7	S1.5 *	7.30	42.0	O3 *	8.53

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: CAPACIT Capacitors

T-Cut: None
Placement Band: 1960-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1988-1989	50.0	37.4	L2 *	12.69	28.7	R4 *	11.84	26.1	R4 *	14.99
1988-1991	50.0	53.7	L1.5 *	12.55	35.4	S3 *	9.72	31.3	R5 *	7.66
1988-1993	83.3	69.7	L1.5 *	4.02	42.3	S3 *	2.77	36.8	S4 *	3.38
1988-1995	85.8	88.1	L1	2.23	53.2	S2	2.88	41.6	R4	2.93
1988-1997	86.9	85.2	L1	1.97	133.9	SC *	1.87	168.4	R1.5 *	1.83
1988-1999	87.2	79.0	L1	1.62	96.3	L0 *	1.56	174.1	R2 *	0.99
1988-2001	77.2	61.4	L1	2.97	154.5	R0.5 *	2.03	156.7	R0.5 *	1.91
1988-2003	77.0	63.6	L1	3.23	156.6	R0.5 *	1.82	156.1	R0.5 *	1.58
1988-2005	70.8	58.0	L0.5	3.90	144.7	SC *	2.18	142.8	SC *	2.33
1988-2007	70.5	60.9	L0	4.19	144.1	SC *	1.68	140.6	SC *	2.13
1988-2009	71.9	69.7	O2	4.07	146.1	SC *	1.41	144.4	SC *	1.64
1988-2011	45.5	48.6	L0.5	2.75	62.4	O3 *	2.63	48.3	L0.5	2.66
1988-2013	32.1	43.7	L1	2.98	41.8	S0	2.93	46.1	L1 *	2.84

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: CAPACIT Capacitors

T-Cut: None

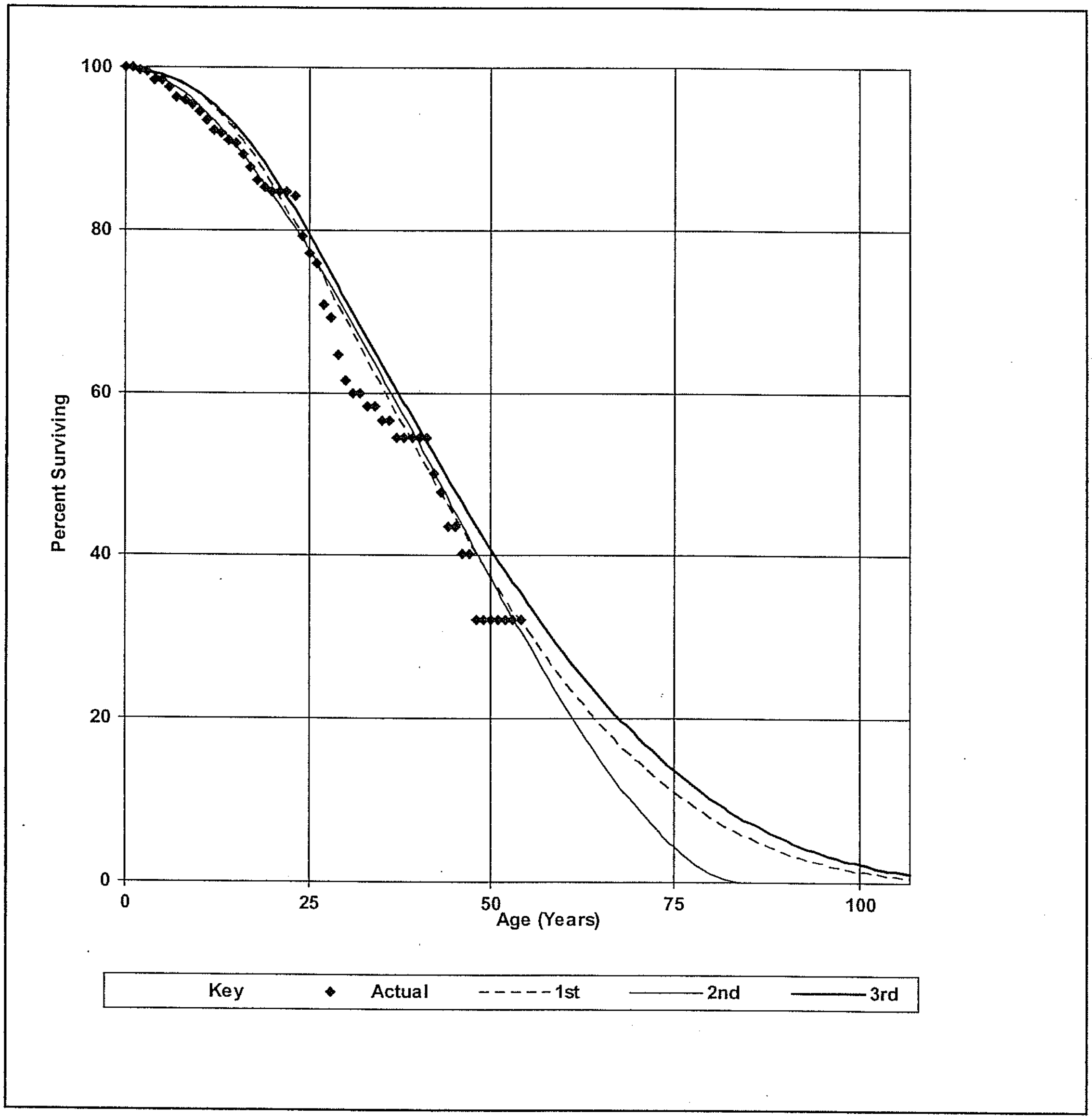
Placement Band: 1960-2012 Observation Band: 1988-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 43.7-L1 2nd: 41.8-S0 3rd: 46.1-L1



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: CAPACIT Capacitors

T-Cut: None

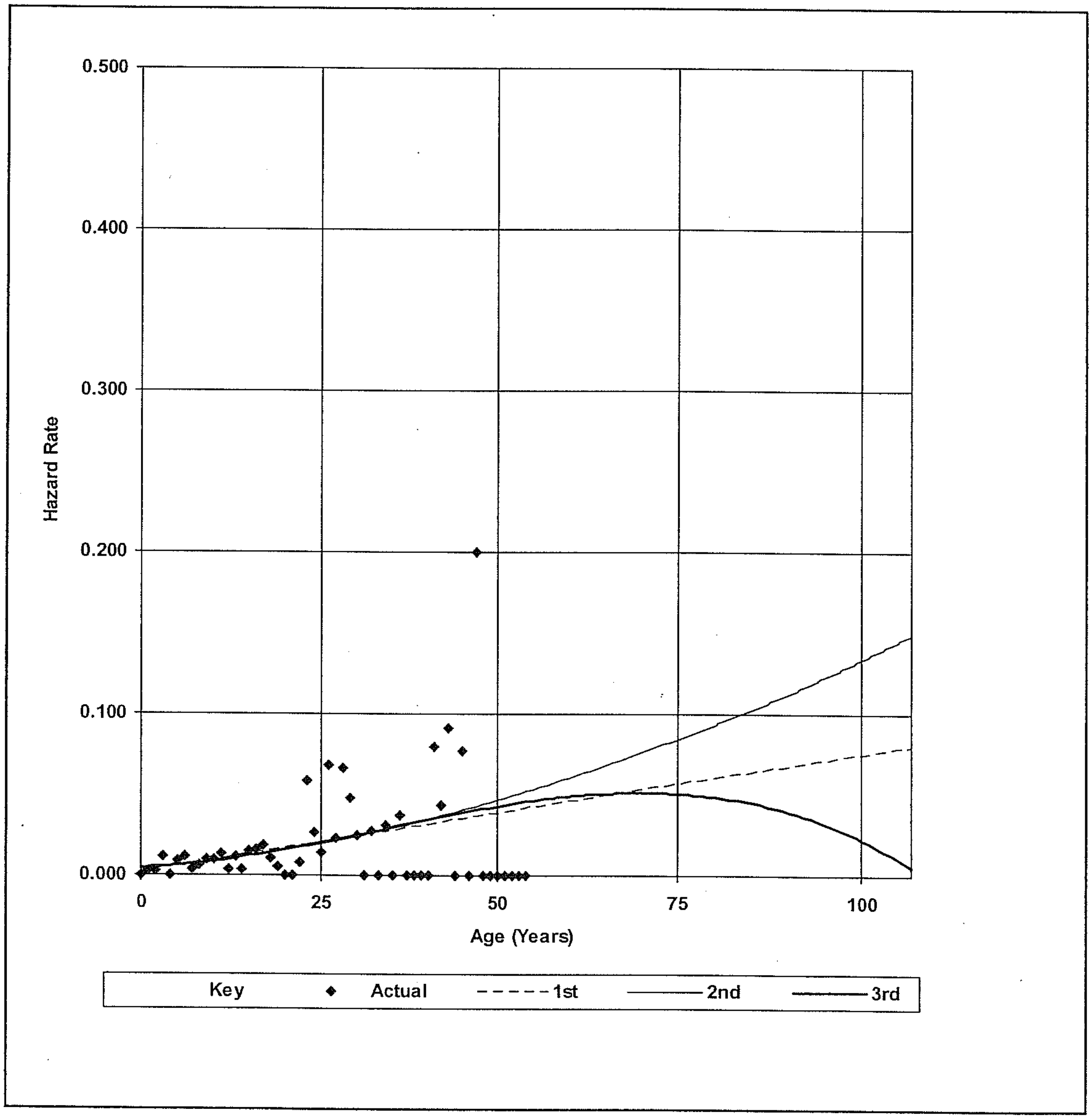
Placement Band: 1960-2012 Observation Band: 1988-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 43.7-L1 2nd: 41.8-S0 3rd: 46.1-L1



Schedule E

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: CAPACIT Capacitors

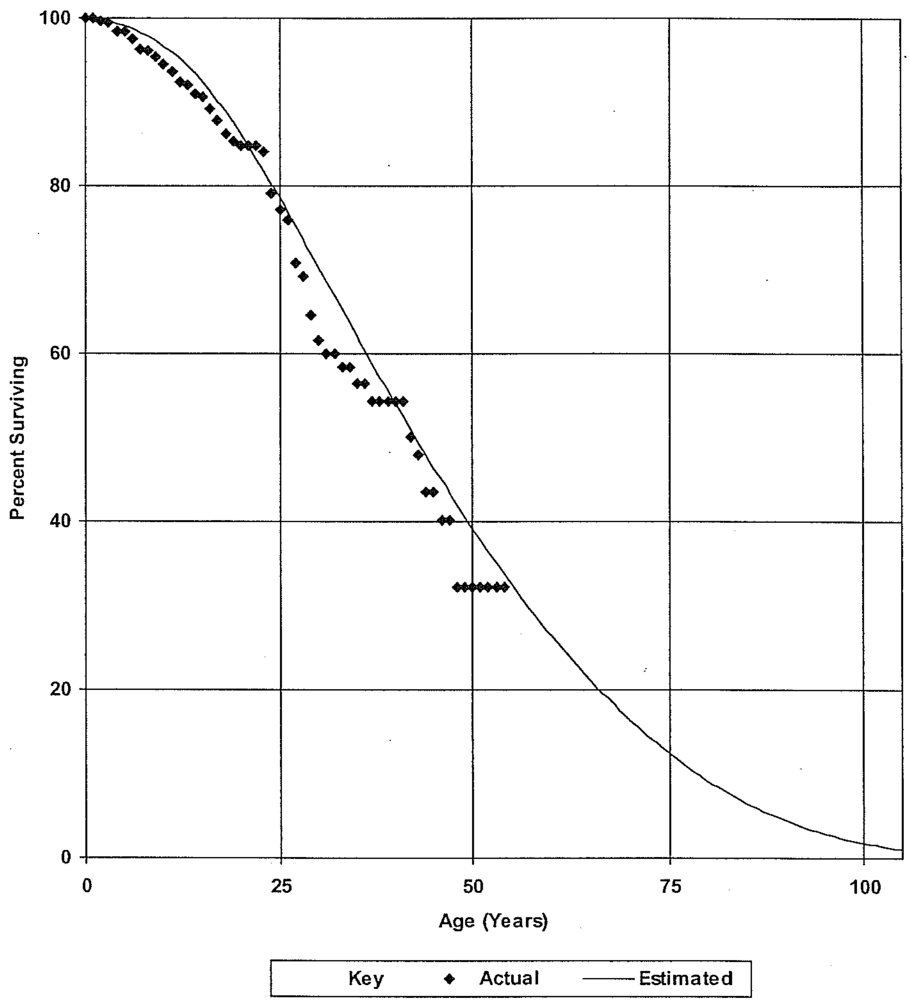
T-Cut: None

Placement Band: 1960-2012

Observation Band: 1988-2013

Estimated Projection Life Curve

45.0-L1



Schedule A

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

Placement Band: 1917 - 2013
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	267	0	0.00000	1.00000	1.00000
0.5	253	1	0.00395	0.99605	1.00000
1.5	262	0	0.00000	1.00000	0.99605
2.5	263	1	0.00380	0.99620	0.99605
3.5	243	2	0.00823	0.99177	0.99226
4.5	232	0	0.00000	1.00000	0.98409
5.5	260	0	0.00000	1.00000	0.98409
6.5	275	4	0.01455	0.98545	0.98409
7.5	273	0	0.00000	1.00000	0.96978
8.5	297	1	0.00337	0.99663	0.96978
9.5	296	1	0.00338	0.99662	0.96651
10.5	305	0	0.00000	1.00000	0.96325
11.5	332	5	0.01506	0.98494	0.96325
12.5	356	3	0.00843	0.99157	0.94874
13.5	366	2	0.00546	0.99454	0.94075
14.5	375	1	0.00267	0.99733	0.93561
15.5	383	5	0.01305	0.98695	0.93311
16.5	393	1	0.00254	0.99746	0.92093
17.5	395	3	0.00759	0.99241	0.91859
18.5	405	5	0.01235	0.98765	0.91161
19.5	409	4	0.00978	0.99022	0.90036
20.5	412	2	0.00485	0.99515	0.89155
21.5	425	2	0.00471	0.99529	0.88722
22.5	413	1	0.00242	0.99758	0.88305
23.5	405	4	0.00988	0.99012	0.88091
24.5	412	3	0.00728	0.99272	0.87221
25.5	396	3	0.00758	0.99242	0.86586
26.5	402	5	0.01244	0.98756	0.85930
27.5	407	6	0.01474	0.98526	0.84861
28.5	417	4	0.00959	0.99041	0.83610
29.5	466	6	0.01288	0.98712	0.82808
30.5	468	3	0.00641	0.99359	0.81742
31.5	468	4	0.00855	0.99145	0.81218
32.5	495	7	0.01414	0.98586	0.80524
33.5	493	10	0.02028	0.97972	0.79385
34.5	479	8	0.01670	0.98330	0.77775
35.5	471	17	0.03609	0.96391	0.76476

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

Placement Band: 1917 - 2013
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	449	5	0.01114	0.98886	0.73715
37.5	439	9	0.02050	0.97950	0.72895
38.5	412	3	0.00728	0.99272	0.71400
39.5	391	4	0.01023	0.98977	0.70880
40.5	391	6	0.01535	0.98465	0.70155
41.5	369	9	0.02439	0.97561	0.69079
42.5	349	8	0.02292	0.97708	0.67394
43.5	324	3	0.00926	0.99074	0.65849
44.5	298	2	0.00671	0.99329	0.65239
45.5	282	4	0.01418	0.98582	0.64801
46.5	268	5	0.01866	0.98134	0.63882
47.5	256	4	0.01563	0.98438	0.62690
48.5	243	7	0.02881	0.97119	0.61711
49.5	226	5	0.02212	0.97788	0.59933
50.5	220	2	0.00909	0.99091	0.58607
51.5	209	11	0.05263	0.94737	0.58074
52.5	194	2	0.01031	0.98969	0.55018
53.5	184	3	0.01630	0.98370	0.54451
54.5	166	12	0.07229	0.92771	0.53563
55.5	150	4	0.02667	0.97333	0.49691
56.5	142	4	0.02817	0.97183	0.48366
57.5	127	5	0.03937	0.96063	0.47003
58.5	120	6	0.05000	0.95000	0.45153
59.5	113	1	0.00885	0.99115	0.42895
60.5	108	3	0.02778	0.97222	0.42516
61.5	95	3	0.03158	0.96842	0.41335
62.5	59	4	0.06780	0.93220	0.40029
63.5	50	2	0.04000	0.96000	0.37315
64.5	43	2	0.04651	0.95349	0.35823
65.5	26	4	0.15385	0.84615	0.34157
66.5	22	5	0.22727	0.77273	0.28902
67.5	16	0	0.00000	1.00000	0.22333
68.5	14	3	0.21429	0.78571	0.22333
69.5	11	0	0.00000	1.00000	0.17547
70.5	11	0	0.00000	1.00000	0.17547
71.5	8	1	0.12500	0.87500	0.17547
72.5	7	0	0.00000	1.00000	0.15354

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

Placement Band: 1917 - 2013
Observation Band: 1981 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
73.5	6	0	0.00000	1.00000	0.15354
74.5	6	1	0.16667	0.83333	0.15354
75.5	5	0	0.00000	1.00000	0.12795
76.5	5	0	0.00000	1.00000	0.12795
77.5	5	0	0.00000	1.00000	0.12795
78.5	4	1	0.25000	0.75000	0.12795
79.5	3	0	0.00000	1.00000	0.09596
80.5	3	0	0.00000	1.00000	0.09596
81.5	2	0	0.00000	1.00000	0.09596
82.5	2	0	0.00000	1.00000	0.09596
83.5	2	0	0.00000	1.00000	0.09596
84.5	2	0	0.00000	1.00000	0.09596
85.5	2	0	0.00000	1.00000	0.09596
86.5	1	0	0.00000	1.00000	0.09596
87.5	1	0	0.00000	1.00000	0.09596
88.5	1	0	0.00000	1.00000	0.09596
89.5	1	0	0.00000	1.00000	0.09596
90.5	1	0	0.00000	1.00000	0.09596
91.5	1	0	0.00000	1.00000	0.09596
92.5	0	0	0.00000	1.00000	0.09596

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

T-Cut: None

Placement Band: 1917-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-1985	58.3	70.1	O3	6.02	103.8	O4 *	4.94	108.6	O4 *	5.41
1982-1986	56.9	63.1	O2	6.66	114.9	O3 *	4.19	111.8	O3 *	4.22
1983-1987	62.3	80.2	O2	4.47	136.0	SC *	3.67	133.7	SC *	2.81
1984-1988	65.6	83.7	O2	5.98	133.5	SC *	2.69	130.9	SC *	3.03
1985-1989	35.6	59.0	L1	3.55	61.9	L1 *	3.31	57.7	S0 *	3.45
1986-1990	31.7	49.7	L0.5	5.00	62.2	O3 *	4.14	73.6	O4 *	3.99
1987-1991	29.8	49.1	L0.5	6.39	64.7	O3 *	4.73	75.6	O4 *	4.89
1988-1992	0.0	42.6	L1	5.29	42.7	L1	5.30	42.3	L1 *	5.28
1989-1993	0.0	46.7	L1	6.80	45.7	L1	6.62	45.0	S0 *	6.53
1990-1994	0.0	48.9	L1.5 *	5.03	46.7	S0	4.79	45.9	S0 *	4.53
1991-1995	4.8	54.8	L1.5 *	6.18	49.9	R1.5	5.76	48.5	R1.5 *	5.25
1992-1996	13.0	57.8	L1.5 *	4.83	51.9	R1.5	6.24	50.3	R1.5 *	6.86
1993-1997	5.8	65.4	L2 *	12.63	57.0	R2.5 *	10.39	56.6	R3 *	9.24
1994-1998	0.0	62.2	L2 *	11.69	55.5	R2.5 *	7.58	56.0	R3 *	5.96
1995-1999	0.0	69.6	L2 *	12.82	57.0	R2.5 *	9.48	58.1	R3 *	6.94
1996-2000	7.7	71.9	L2 *	12.57	61.5	R3 *	8.53	61.8	R4 *	6.64
1997-2001	7.0	69.7	S1.5 *	12.29	59.8	R3 *	8.48	61.7	R4 *	5.92
1998-2002	9.8	73.3	L2 *	14.51	62.7	R2.5 *	9.79	63.3	R4 *	8.61
1999-2003	18.3	67.5	L3 *	6.23	58.8	R2.5 *	8.23	61.5	R4 *	7.17
2000-2004	28.4	66.3	L3 *	7.16	61.5	R3 *	6.62	61.3	R3 *	6.69
2001-2005	32.9	67.5	S1.5 *	6.12	63.6	R3 *	6.36	63.4	S2 *	6.28
2002-2006	33.2	64.5	L2 *	5.59	62.7	S2 *	6.50	63.8	L3 *	5.94
2003-2007	33.5	67.1	L2 *	5.17	64.9	S2 *	5.83	70.0	L3 *	4.97
2004-2008	39.8	69.2	L2 *	6.20	66.9	S2 *	6.53	84.3	L0.5 *	5.03
2005-2009	11.6	66.3	L2 *	10.22	64.8	S2 *	7.71	66.5	L3 *	8.11
2006-2010	8.5	59.3	L2 *	7.59	59.3	S2 *	5.86	65.4	L3 *	6.22
2007-2011	13.1	55.0	L2 *	5.39	55.4	S1.5 *	4.25	59.6	L3 *	3.53
2008-2012	11.2	53.2	L2 *	5.51	53.2	L2 *	5.31	63.6	L2 *	4.20
2009-2013	8.6	50.2	L2 *	4.61	50.2	L2 *	4.61	62.1	L1.5 *	3.99

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

T-Cut: None

Placement Band: 1917-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-2013	9.6	57.8	L1.5*	5.20	53.8	S0.5	2.91	53.6	R1.5	2.82
1983-2013	9.8	58.3	L1.5*	4.84	55.1	R1.5	2.98	54.9	R1.5	2.89
1985-2013	9.8	59.0	L2*	4.99	56.0	S1	3.13	55.9	S1	3.03
1987-2013	9.2	58.3	L2*	4.96	55.4	S1	3.16	55.2	S1	3.07
1989-2013	8.9	58.5	L2*	5.11	56.0	S1	3.29	55.9	S1	3.24
1991-2013	8.9	60.1	L2*	5.78	58.0	S1.5	3.70	58.0	S1.5	3.66
1993-2013	10.7	61.8	L2*	6.32	60.2	S2	4.06	60.4	S2	4.13
1995-2013	11.0	61.8	L2*	6.05	60.4	S2	3.90	60.7	S2	3.99
1997-2013	12.6	60.7	L2*	5.41	60.2	S2*	3.73	61.0	L3*	3.70
1999-2013	14.6	60.9	L2*	4.73	60.3	S2*	3.46	62.3	L3*	3.26
2001-2013	17.8	58.9	L2*	4.85	58.6	S1.5*	4.34	68.0	L2*	3.43
2003-2013	16.3	57.6	L2*	4.77	57.5	S1.5*	4.19	69.9	L2*	3.39
2005-2013	14.8	56.9	L2*	5.17	56.7	S1*	4.68	71.4	L1.5*	3.78
2007-2013	12.0	53.9	L2*	4.81	53.9	L2*	4.50	66.1	L1.5*	3.66
2009-2013	8.6	50.2	L2*	4.61	50.2	L2*	4.61	62.1	L1.5*	3.99
2011-2013	8.3	46.6	L1.5*	9.11	48.2	L1.5*	7.86	60.4	O3*	9.52
2013-2013	13.9	44.3	L1.5*	14.70	44.4	L1.5*	15.78	58.2	O2*	10.38

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

T-Cut: None

Placement Band: 1917-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1981-1982	59.3	102.2	O4*	7.10	105.7	O4*	6.42	106.8	O4*	6.91
1981-1984	52.9	56.3	O2	7.58	87.4	O4*	6.31	94.2	O4*	7.02
1981-1986	59.4	73.4	O3	5.58	115.6	O3*	3.84	114.9	O3*	4.19
1981-1988	59.3	69.1	O2	7.08	117.6	SC*	3.58	115.2	O3*	4.25
1981-1990	36.9	53.8	L0	4.31	61.5	O2*	3.70	88.8	O4*	3.45
1981-1992	0.0	49.8	L0.5	3.08	49.1	L0.5	3.16	48.8	L0.5	3.18
1981-1994	0.0	51.7	L0.5	3.09	49.1	S-.5	2.98	48.4	S-.5	2.89
1981-1996	15.5	55.1	L0.5	2.99	51.5	S-.5	3.44	50.1	R0.5	3.29
1981-1998	10.1	55.5	L1	4.88	50.2	R0.5	3.68	49.7	R1	2.91
1981-2000	6.2	58.5	L1	5.51	51.9	R1	3.81	51.3	R1*	2.85
1981-2002	6.2	59.4	L1	6.85	52.3	R1	3.74	52.0	R1*	2.24
1981-2004	5.8	59.3	L1*	7.52	52.0	R1	3.60	52.0	R1.5	2.22
1981-2006	9.2	60.5	L1*	6.80	53.6	R1	3.12	53.2	R1.5	2.04
1981-2008	10.8	60.9	L1*	6.21	54.4	R1	2.80	54.0	R1.5	2.10
1981-2010	8.4	59.8	L1.5*	6.79	54.0	R1	3.33	53.7	R1.5	2.72
1981-2012	10.1	58.6	L1.5*	5.45	54.1	R1	2.96	53.8	R1.5	2.77
1981-2013	9.6	57.8	L1.5*	5.20	53.8	S0.5	2.91	53.6	R1.5	2.82

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

T-Cut: None

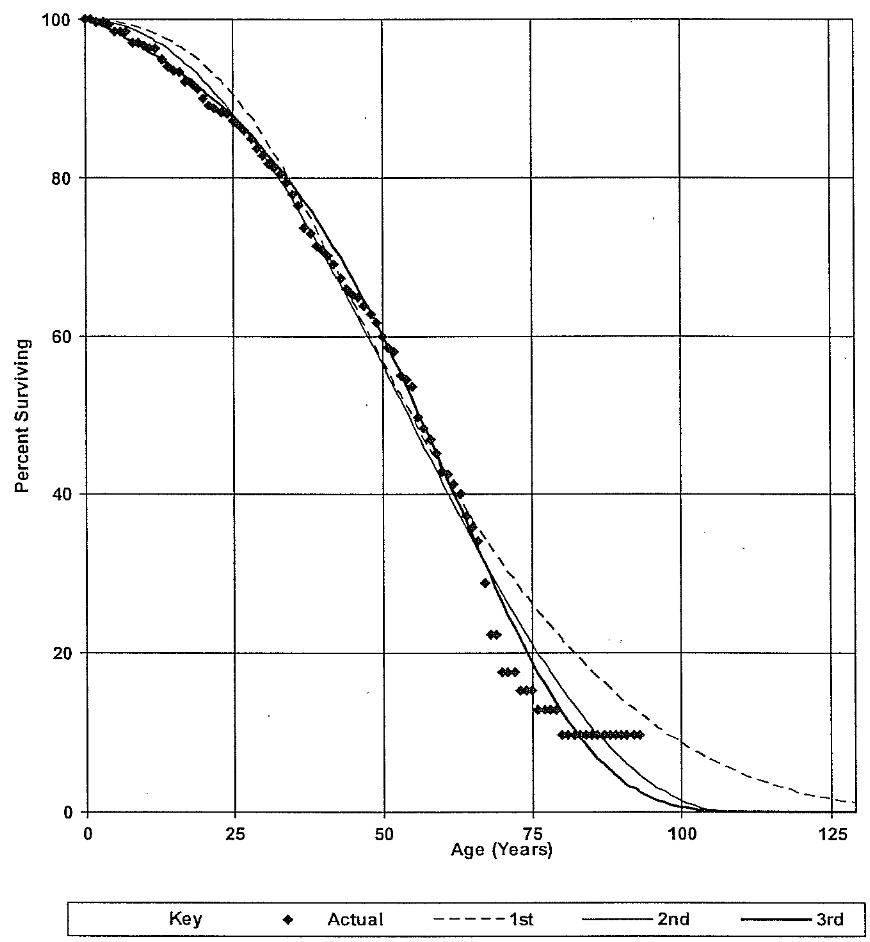
Placement Band: 1917-2013 Observation Band: 1981-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 57.8-L1.5 2nd: 53.8-S0.5 3rd: 53.6-R1.5



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

T-Cut: None

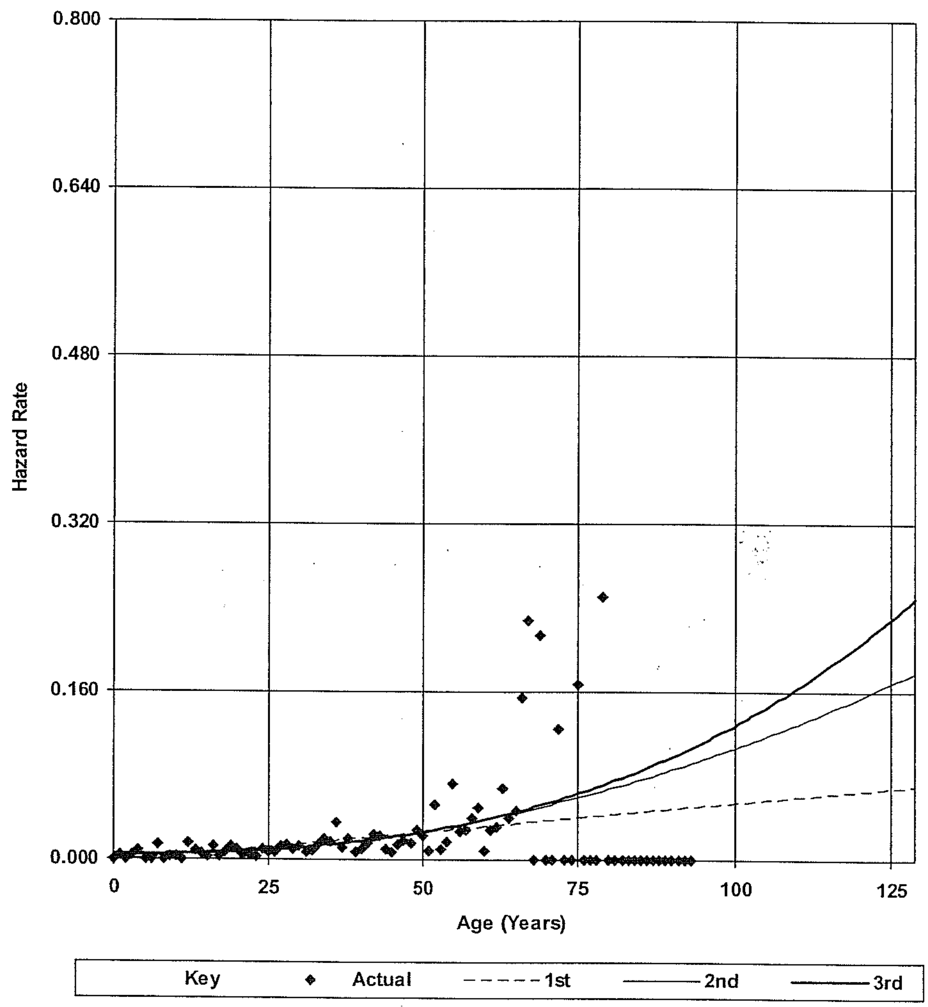
Placement Band: 1917-2013 Observation Band: 1981-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 57.8-L1.5 2nd: 53.8-S0.5 3rd: 53.6-R1.5



Schedule E

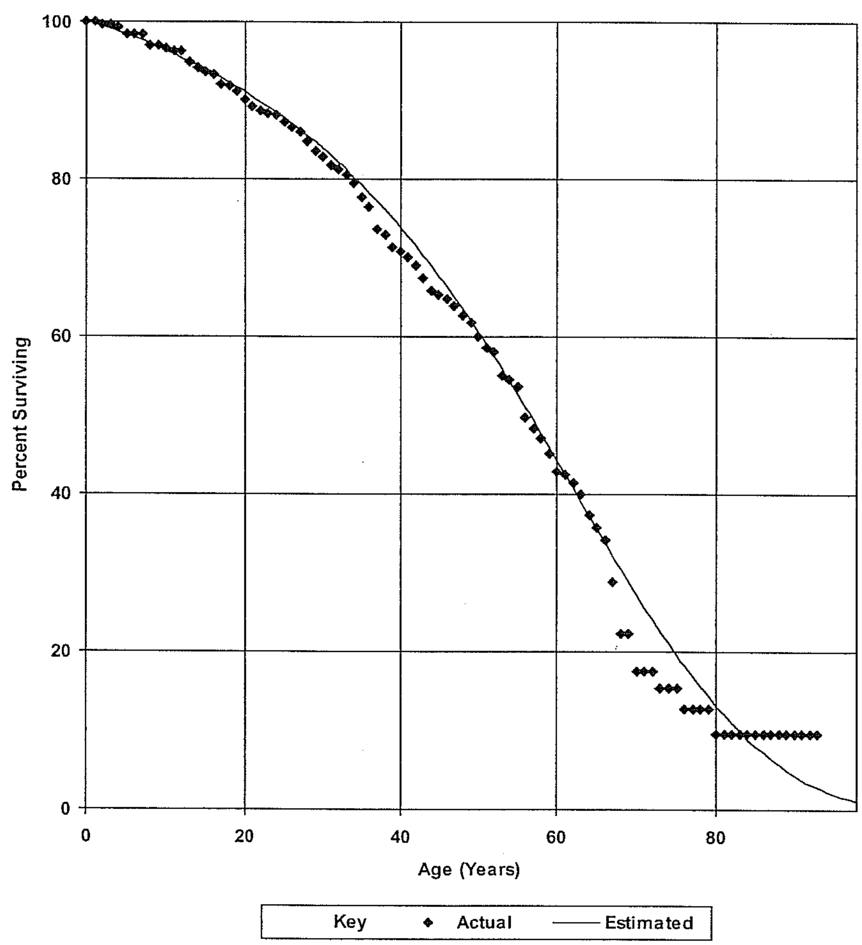
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSHVSDTR HV Stepdown Transformers

T-Cut: None
Placement Band: 1917-2013
Observation Band: 1981-2013
54.0-R1.5

Estimated Projection Life Curve



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSLVSDTR LV Stepdown Transformers

Placement Band: 1947 - 1973
Observation Band: 1987 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	0	0	0.00000	1.00000	1.00000
0.5	0	0	0.00000	1.00000	1.00000
1.5	0	0	0.00000	1.00000	1.00000
2.5	0	0	0.00000	1.00000	1.00000
3.5	0	0	0.00000	1.00000	1.00000
4.5	0	0	0.00000	1.00000	1.00000
5.5	0	0	0.00000	1.00000	1.00000
6.5	0	0	0.00000	1.00000	1.00000
7.5	0	0	0.00000	1.00000	1.00000
8.5	0	0	0.00000	1.00000	1.00000
9.5	0	0	0.00000	1.00000	1.00000
10.5	0	0	0.00000	1.00000	1.00000
11.5	0	0	0.00000	1.00000	1.00000
12.5	0	0	0.00000	1.00000	1.00000
13.5	2	0	0.00000	1.00000	1.00000
14.5	2	0	0.00000	1.00000	1.00000
15.5	2	0	0.00000	1.00000	1.00000
16.5	2	0	0.00000	1.00000	1.00000
17.5	2	0	0.00000	1.00000	1.00000
18.5	2	0	0.00000	1.00000	1.00000
19.5	2	0	0.00000	1.00000	1.00000
20.5	2	0	0.00000	1.00000	1.00000
21.5	2	0	0.00000	1.00000	1.00000
22.5	2	0	0.00000	1.00000	1.00000
23.5	2	0	0.00000	1.00000	1.00000
24.5	2	0	0.00000	1.00000	1.00000
25.5	5	1	0.20000	0.80000	1.00000
26.5	4	0	0.00000	1.00000	0.80000
27.5	4	0	0.00000	1.00000	0.80000
28.5	4	0	0.00000	1.00000	0.80000
29.5	4	0	0.00000	1.00000	0.80000
30.5	4	0	0.00000	1.00000	0.80000
31.5	4	1	0.25000	0.75000	0.80000
32.5	3	0	0.00000	1.00000	0.60000
33.5	3	1	0.33333	0.66667	0.60000
34.5	2	0	0.00000	1.00000	0.40000
35.5	4	0	0.00000	1.00000	0.40000

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSLVSDTR LV Stepdown Transformers

Placement Band: 1947 - 1973
Observation Band: 1987 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	4	0	0.00000	1.00000	0.40000
37.5	4	0	0.00000	1.00000	0.40000
38.5	4	0	0.00000	1.00000	0.40000
39.5	8	0	0.00000	1.00000	0.40000
40.5	7	0	0.00000	1.00000	0.40000
41.5	7	0	0.00000	1.00000	0.40000
42.5	7	1	0.14286	0.85714	0.40000
43.5	6	0	0.00000	1.00000	0.34286
44.5	6	0	0.00000	1.00000	0.34286
45.5	6	0	0.00000	1.00000	0.34286
46.5	6	0	0.00000	1.00000	0.34286
47.5	6	0	0.00000	1.00000	0.34286
48.5	6	1	0.16667	0.83333	0.34286
49.5	5	0	0.00000	1.00000	0.28571
50.5	5	0	0.00000	1.00000	0.28571
51.5	5	0	0.00000	1.00000	0.28571
52.5	4	0	0.00000	1.00000	0.28571
53.5	4	0	0.00000	1.00000	0.28571
54.5	4	0	0.00000	1.00000	0.28571
55.5	4	0	0.00000	1.00000	0.28571
56.5	4	0	0.00000	1.00000	0.28571
57.5	4	0	0.00000	1.00000	0.28571
58.5	4	0	0.00000	1.00000	0.28571
59.5	4	0	0.00000	1.00000	0.28571
60.5	4	0	0.00000	1.00000	0.28571
61.5	4	0	0.00000	1.00000	0.28571
62.5	3	0	0.00000	1.00000	0.28571
63.5	3	0	0.00000	1.00000	0.28571
64.5	3	0	0.00000	1.00000	0.28571
65.5	3	0	0.00000	1.00000	0.28571
66.5	0	0	0.00000	1.00000	0.28571

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSLVSDTR LV Stepdown Transformers

T-Cut: None
Placement Band: 1947-1973
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-1991	66.7	48.5	O4*	48.66	76.2	O4*	22.13	29.4	L2*	30.91
1988-1992	100.0				No Retirements					
1989-1993	50.0	58.7	O4*	39.20	76.0	O4*	18.18	50.6	O3*	19.53
1990-1994	41.7	28.2	O2	34.22	55.2	O4*	21.35	57.9	O4*	18.73
1991-1995	25.0	23.5	O3	41.87	47.6	O3*	21.71	49.3	O3*	19.84
1992-1996	18.8	31.4	L1.5*	22.98	44.6	L2*	17.95	30.2	L4*	27.18
1993-1997	18.8	24.5	L0	35.36	38.0	L3*	21.72	30.2	L4*	27.07
1994-1998	37.5	44.5	S3*	16.16	57.6	O3*	26.41	0.3	S0*	92.01
1995-1999	75.0	54.7	S3*	13.39	54.1	S3*	10.93	0.6	O2*	96.75
1996-2000	80.0	55.0	L3*	14.53	87.4	O3*	19.87	0.3	SC*	97.42
1997-2001	100.0				No Retirements					
1998-2002	100.0				No Retirements					
1999-2003	100.0				No Retirements					
2000-2004	100.0				No Retirements					
2001-2005	100.0				No Retirements					
2002-2006	100.0				No Retirements					
2003-2007	50.0	5.7	O4*	72.58	14.4	O3*	62.12	40.4	L4*	20.18
2004-2008	50.0	4.4	O4*	73.92	2.6	O3*	76.78	41.3	L3*	19.15
2005-2009	50.0	3.4	O4*	74.99	1.0	O3*	78.90	35.1	L3*	29.27
2006-2010	50.0	2.6	O4*	75.87	0.6	O3*	79.27	0.3	SC*	79.90
2007-2011	50.0	2.0	O4*	76.58	0.3	R1*	79.42	0.3	SC*	79.53
2008-2012	100.0				No Retirements					
2009-2013	100.0				No Retirements					

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSLVSDTR LV Stepdown Transformers

T-Cut: None
Placement Band: 1947-1973
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-2013	28.6	35.7	O4 *	38.32	76.0	O4 *	8.74	45.4	L1 *	6.40
1989-2013	35.7	44.2	O4 *	37.59	91.4	O4 *	7.23	51.3	L1 *	7.14
1991-2013	27.8	32.6	O4 *	43.81	82.1	O4 *	7.76	46.8	L1.5 *	7.37
1993-2013	27.8	21.5	O4 *	51.27	71.2	O4 *	8.95	43.1	L2 *	9.21
1995-2013	55.6	51.2	O4 *	43.70	107.8	O3 *	8.18	56.2	L1.5 *	9.83
1997-2013	50.0	53.0	O4 *	41.74	74.9	O4 *	28.67	56.1	S1 *	7.64
1999-2013	50.0	37.3	O4 *	49.55	39.9	O4 *	47.82	54.5	S1 *	7.31
2001-2013	50.0	23.3	O4 *	57.35	11.1	O4 *	64.91	52.6	L2 *	7.77
2003-2013	50.0	12.6	O4 *	64.46	3.3	O3 *	74.00	43.5	L1.5 *	18.88
2005-2013	50.0	6.1	O4 *	70.28	1.2	O3 *	77.26	0.5	L5 *	78.36
2007-2013	50.0	2.9	O4 *	74.55	0.4	S3 *	78.44	0.3	SC *	78.82
2009-2013	100.0				No Retirements					
2011-2013	100.0				No Retirements					
2013-2013	100.0				No Retirements					

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSLVSDTR LV Stepdown Transformers

T-Cut: None
Placement Band: 1947-1973
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1987-1988	66.7	13.0	O4*	69.69	30.5	L2 *	41.86	20.6	L5 *	49.95
1987-1990	66.7	37.9	O4*	54.05	61.4	O4 *	27.62	26.4	L3 *	36.77
1987-1992	66.7	57.4	O4*	44.37	89.3	O4 *	17.64	32.2	L2 *	25.73
1987-1994	27.8	25.1	O4*	38.61	60.2	O4 *	11.51	32.0	L2 *	15.31
1987-1996	20.8	30.5	O2	21.12	58.8	O4 *	9.52	32.2	L2 *	13.29
1987-1998	20.8	30.9	O2	22.69	70.9	O4 *	8.82	35.6	L2 *	8.70
1987-2000	26.7	31.6	O3	26.28	77.9	O4 *	8.00	39.0	L2 *	8.50
1987-2002	26.7	33.3	O3	27.38	83.0	O4 *	8.05	42.9	L1.5 *	7.59
1987-2004	27.4	37.3	O4*	28.26	86.9	O4 *	8.51	47.5	L1 *	7.82
1987-2006	41.1	43.6	O4*	33.03	90.0	O4 *	7.28	51.6	L0.5 *	7.53
1987-2008	27.4	34.2	O4*	38.21	76.5	O4 *	7.10	44.0	L1 *	6.91
1987-2010	28.6	35.0	O4*	38.47	76.9	O4 *	7.53	44.6	L1 *	6.67
1987-2012	28.6	35.5	O4*	38.41	76.5	O4 *	8.26	45.1	L1 *	6.48
1987-2013	28.6	35.7	O4*	38.32	76.0	O4 *	8.74	45.4	L1 *	6.40

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSLVSDTR LV Stepdown Transformers

T-Cut: None

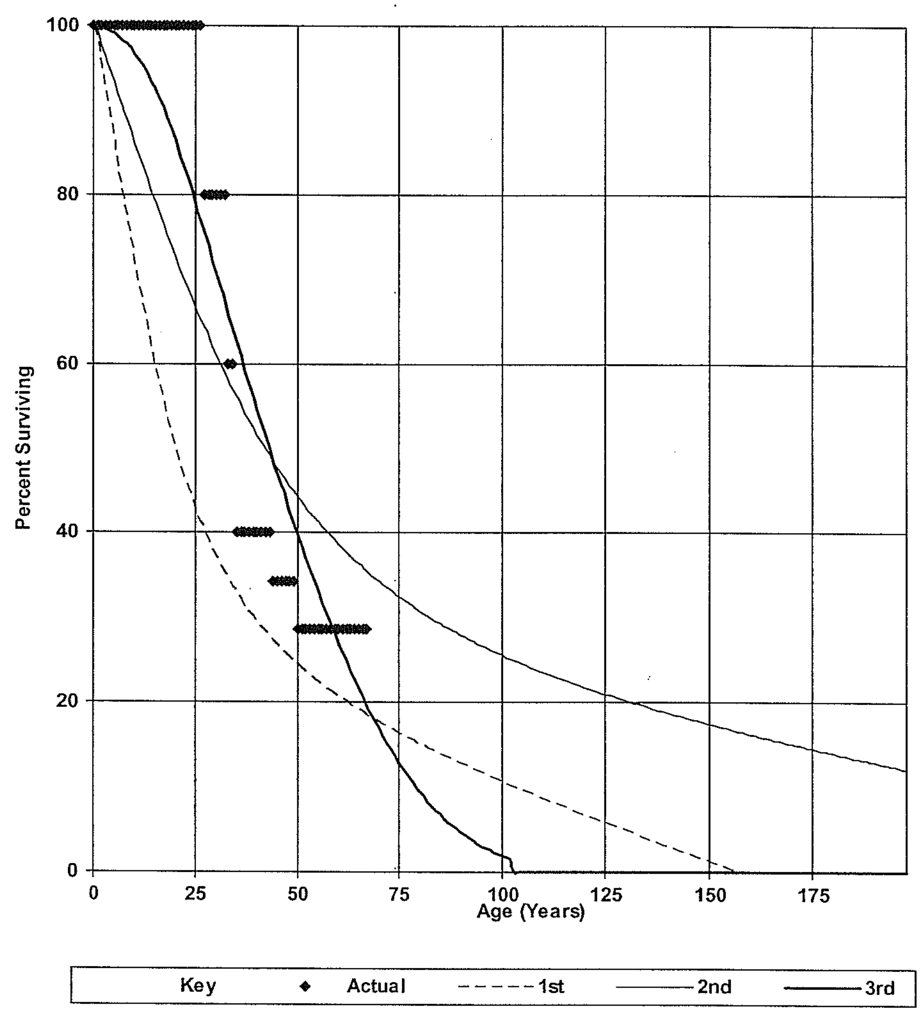
Placement Band: 1947-1973 Observation Band: 1987-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 35.7-O4 2nd: 76.0-O4 3rd: 45.4-L1



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSLVSDTR LV Stepdown Transformers

T-Cut: None

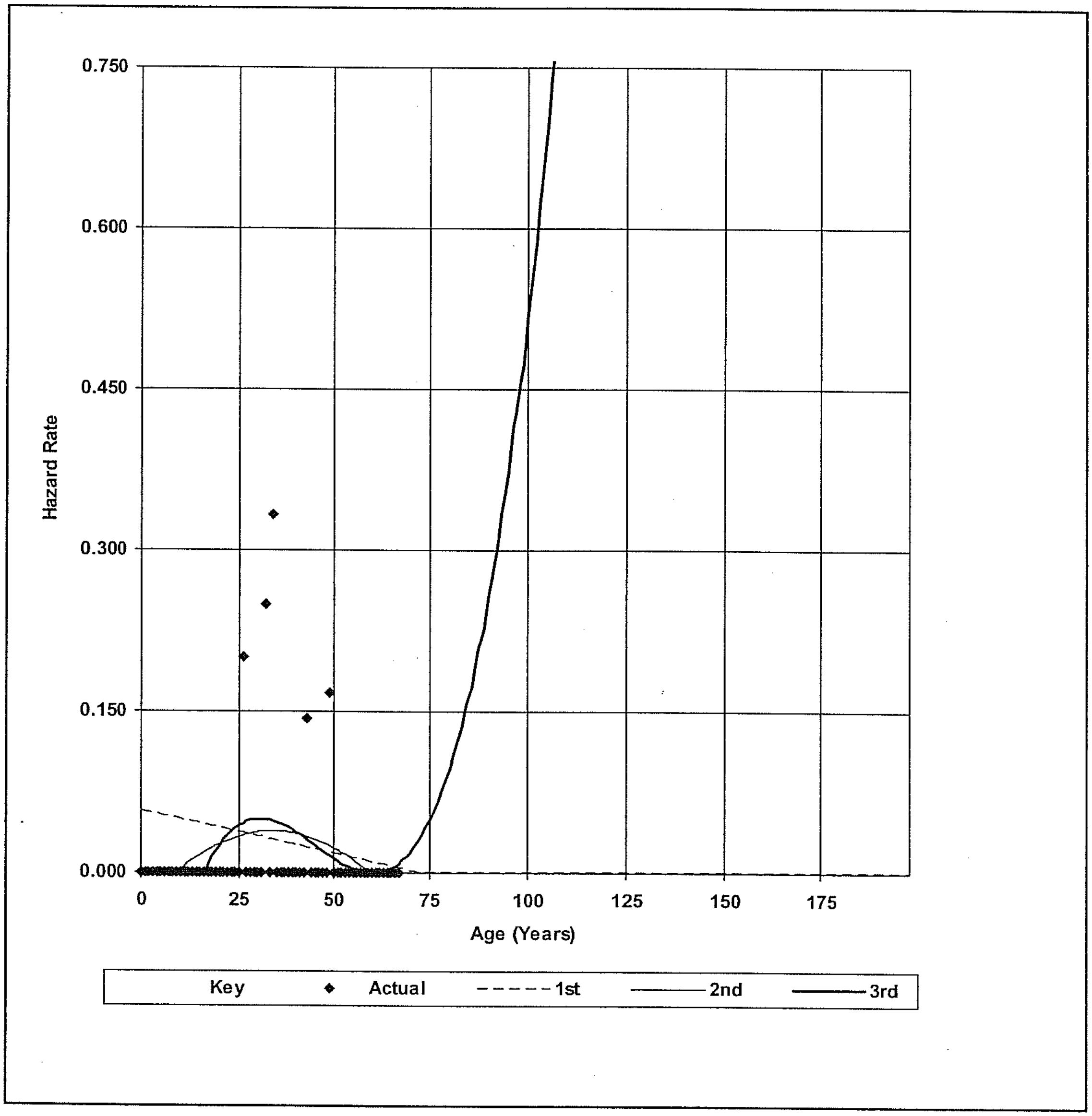
Placement Band: 1947-1973 Observation Band: 1987-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 35.7-O4 2nd: 76.0-O4 3rd: 45.4-L1



Schedule E

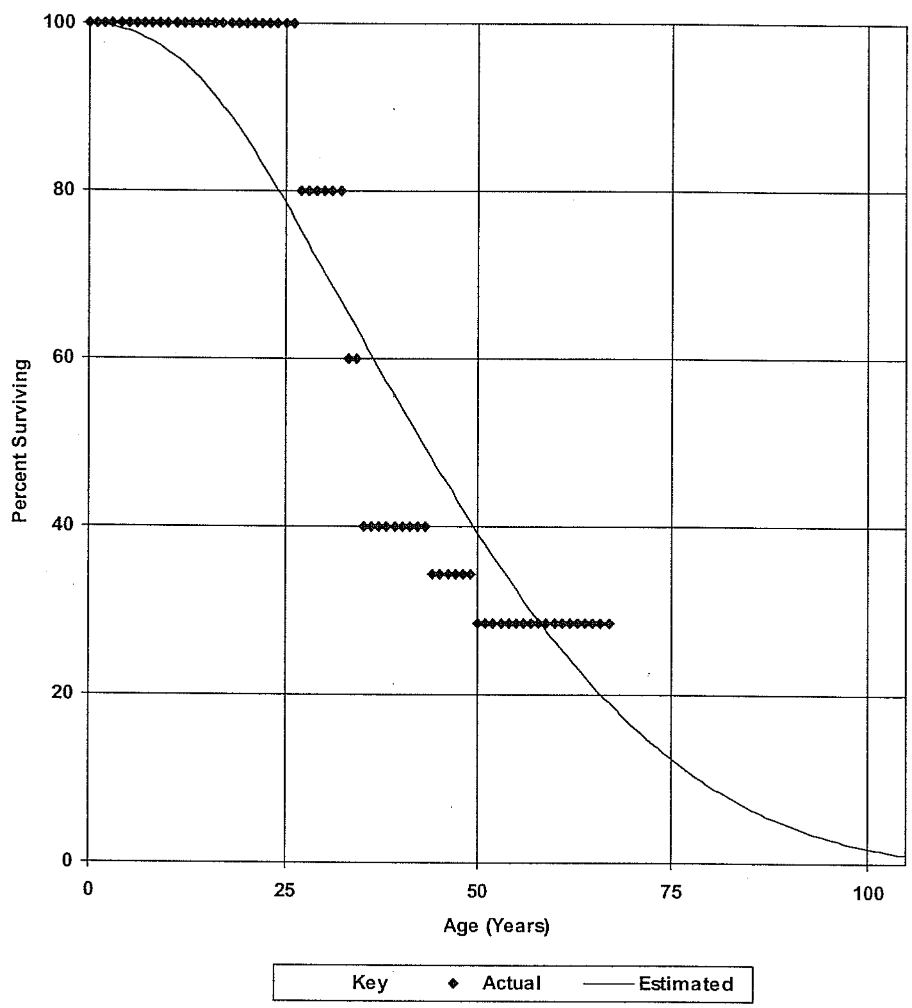
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: TSLVSDTR LV Stepdown Transformers

T-Cut: None
Placement Band: 1947-1973
Observation Band: 1987-2013
45.0-L1

Estimated Projection Life Curve



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REACTOR Reactors

Placement Band: 1966 - 2013
Observation Band: 2000 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	411	2	0.00487	0.99513	1.00000
0.5	403	0	0.00000	1.00000	0.99513
1.5	335	2	0.00597	0.99403	0.99513
2.5	291	0	0.00000	1.00000	0.98919
3.5	282	0	0.00000	1.00000	0.98919
4.5	246	6	0.02439	0.97561	0.98919
5.5	191	4	0.02094	0.97906	0.96507
6.5	184	0	0.00000	1.00000	0.94486
7.5	200	0	0.00000	1.00000	0.94486
8.5	182	0	0.00000	1.00000	0.94486
9.5	142	10	0.07042	0.92958	0.94486
10.5	125	1	0.00800	0.99200	0.87832
11.5	95	0	0.00000	1.00000	0.87129
12.5	91	0	0.00000	1.00000	0.87129
13.5	87	1	0.01149	0.98851	0.87129
14.5	89	0	0.00000	1.00000	0.86127
15.5	90	3	0.03333	0.96667	0.86127
16.5	81	3	0.03704	0.96296	0.83257
17.5	69	0	0.00000	1.00000	0.80173
18.5	69	0	0.00000	1.00000	0.80173
19.5	69	0	0.00000	1.00000	0.80173
20.5	60	3	0.05000	0.95000	0.80173
21.5	44	0	0.00000	1.00000	0.76164
22.5	41	0	0.00000	1.00000	0.76164
23.5	42	0	0.00000	1.00000	0.76164
24.5	37	3	0.08108	0.91892	0.76164
25.5	28	0	0.00000	1.00000	0.69989
26.5	28	0	0.00000	1.00000	0.69989
27.5	28	0	0.00000	1.00000	0.69989
28.5	28	6	0.21429	0.78571	0.69989
29.5	24	0	0.00000	1.00000	0.54991
30.5	18	0	0.00000	1.00000	0.54991
31.5	18	0	0.00000	1.00000	0.54991
32.5	18	0	0.00000	1.00000	0.54991
33.5	20	3	0.15000	0.85000	0.54991
34.5	14	0	0.00000	1.00000	0.46743
35.5	14	0	0.00000	1.00000	0.46743

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REACTOR Reactors

Placement Band: 1966 - 2013
Observation Band: 2000 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	14	0	0.00000	1.00000	0.46743
37.5	8	0	0.00000	1.00000	0.46743
38.5	8	0	0.00000	1.00000	0.46743
39.5	8	0	0.00000	1.00000	0.46743
40.5	8	0	0.00000	1.00000	0.46743
41.5	8	0	0.00000	1.00000	0.46743
42.5	8	0	0.00000	1.00000	0.46743
43.5	2	1	0.50000	0.50000	0.46743
44.5	1	1	1.00000	0.00000	0.23371
45.5	0	0	0.00000	1.00000	0.00000

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REACTOR Reactors

T-Cut: None

Placement Band: 1966-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2004	75.8	144.3	SC *	3.59	144.3	SC *	3.67	36.4	R1 *	2.99
2001-2005	76.7	149.5	SC *	3.13	147.9	SC *	3.54	37.3	R1 *	3.00
2002-2006	66.3	116.3	SC *	4.76	132.9	SC *	3.22	37.9	R1 *	2.51
2003-2007	72.6	63.4	L0	6.20	146.3	SC *	3.92	67.7	R1 *	3.80
2004-2008	51.3	37.2	L1	5.78	98.4	O4 *	4.45	99.2	O4 *	4.62
2005-2009	53.6	39.0	L1	5.92	102.8	O4 *	5.15	102.3	O4 *	5.12
2006-2010	18.2	32.8	L1	6.23	52.0	O4 *	5.98	62.1	O4 *	5.82
2007-2011	0.0	34.0	L1 *	6.87	33.3	S0	7.16	32.4	R1 *	8.20
2008-2012	0.0	29.3	L1.5 *	5.76	29.3	S0.5	5.46	29.3	S0.5	5.48
2009-2013	0.0	34.8	L1.5 *	6.55	33.8	S1	6.22	33.6	R1.5	6.84

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REACTOR Reactors

T-Cut: None

Placement Band: 1966-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2013	0.0	37.6	L1	6.21	36.6	L1	6.10	34.6	R1	5.94
2002-2013	0.0	36.0	L1	5.84	35.6	L1	5.79	33.7	R1	5.64
2004-2013	0.0	35.7	L1 *	6.03	35.0	L1.5	5.92	34.1	S0.5	5.79
2006-2013	0.0	33.5	L1.5 *	5.12	33.3	L1.5	5.07	33.0	L1.5 *	5.10
2008-2013	0.0	32.4	L1.5 *	6.50	32.1	S0.5	5.79	32.1	S0.5	5.79
2010-2013	0.0	32.3	L1.5 *	7.01	32.2	S1	6.87	32.2	S1 *	7.37
2012-2013	26.7	31.5	L1.5 *	7.63	31.5	L2 *	7.70	54.6	O4 *	9.67

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REACTOR Reactors

T-Cut: None

Placement Band: 1966-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2001	93.3	199.0	SQ	6.58	199.0	SQ	6.58	199.0	SQ	6.58
2000-2003	78.0	144.5	SC *	4.66	144.4	SC *	5.05	37.9	R1 *	3.92
2000-2005	77.6	155.4	R0.5 *	2.93	154.3	R0.5 *	3.14	39.3	R1.5 *	2.46
2000-2007	72.6	87.4	O3	4.38	141.5	SC *	3.00	45.2	R1 *	2.05
2000-2009	56.1	47.3	L0	3.70	122.3	SC *	2.82	122.3	SC *	2.78
2000-2011	0.0	40.8	L0.5	7.28	39.7	L0.5	7.31	35.0	R1 *	7.48
2000-2013	0.0	37.6	L1	6.21	36.6	L1	6.10	34.6	R1	5.94

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REACTOR Reactors

T-Cut: None

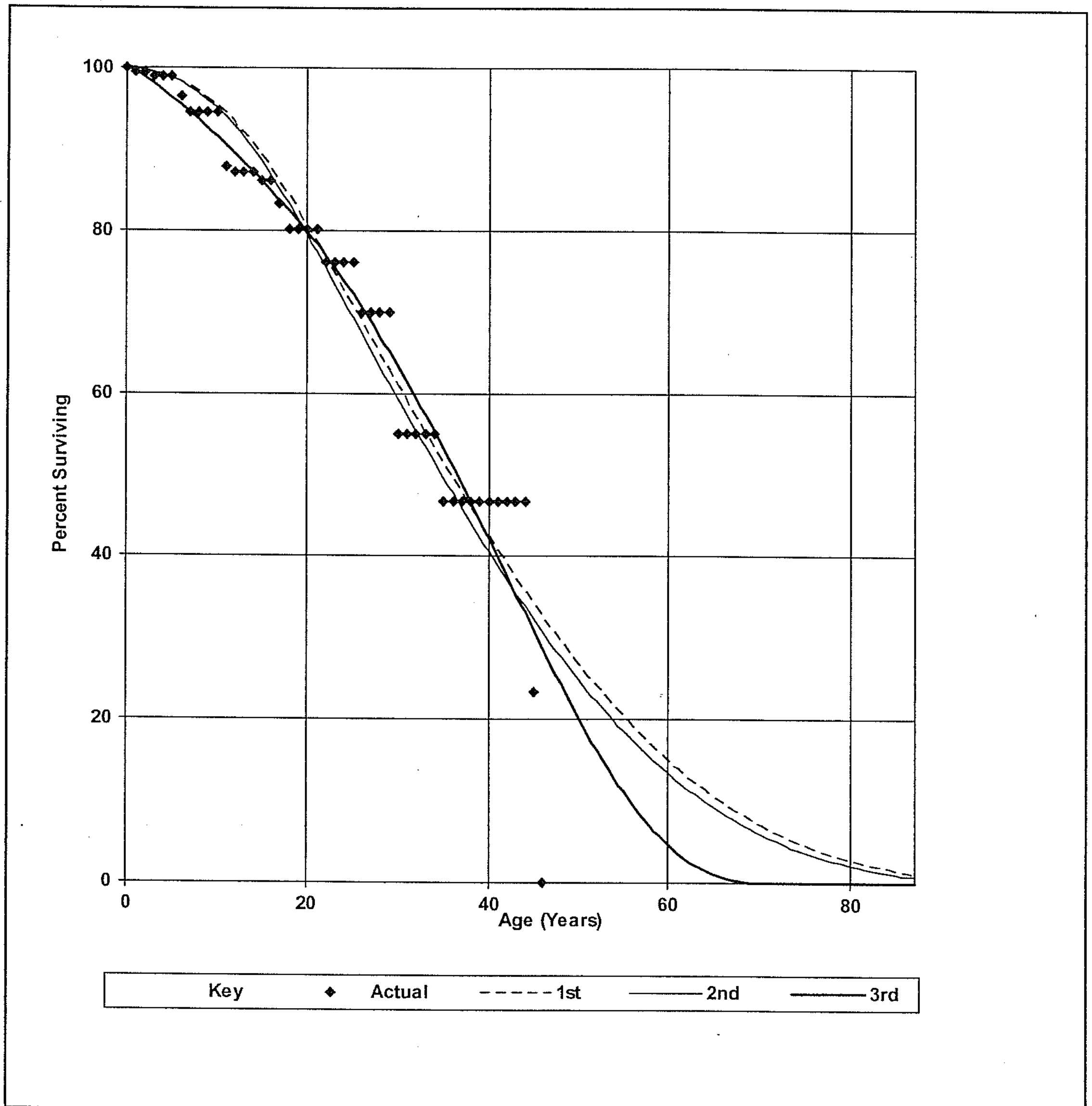
Placement Band: 1966-2013 Observation Band: 2000-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 37.6-L1 2nd: 36.6-L1 3rd: 34.6-R1



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REACTOR Reactors

T-Cut: None

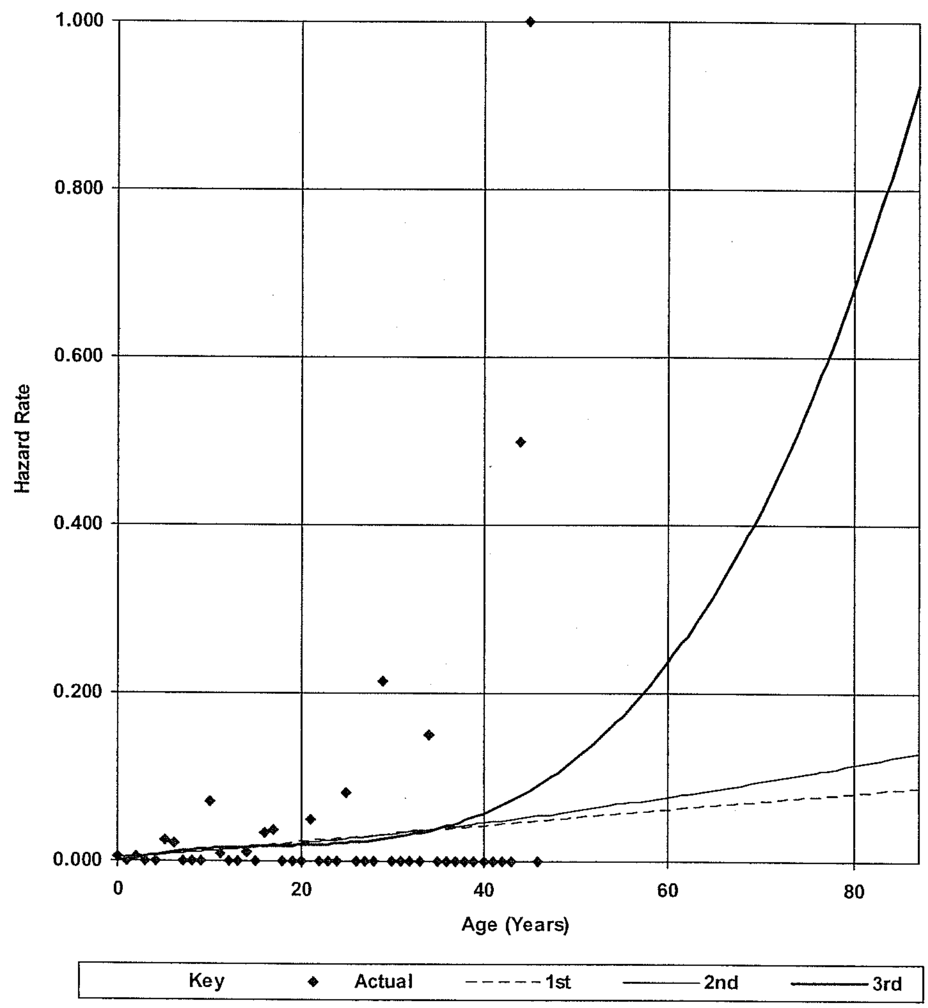
Placement Band: 1966-2013 Observation Band: 2000-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 37.6-L1 2nd: 36.6-L1 3rd: 34.6-R1



Schedule E

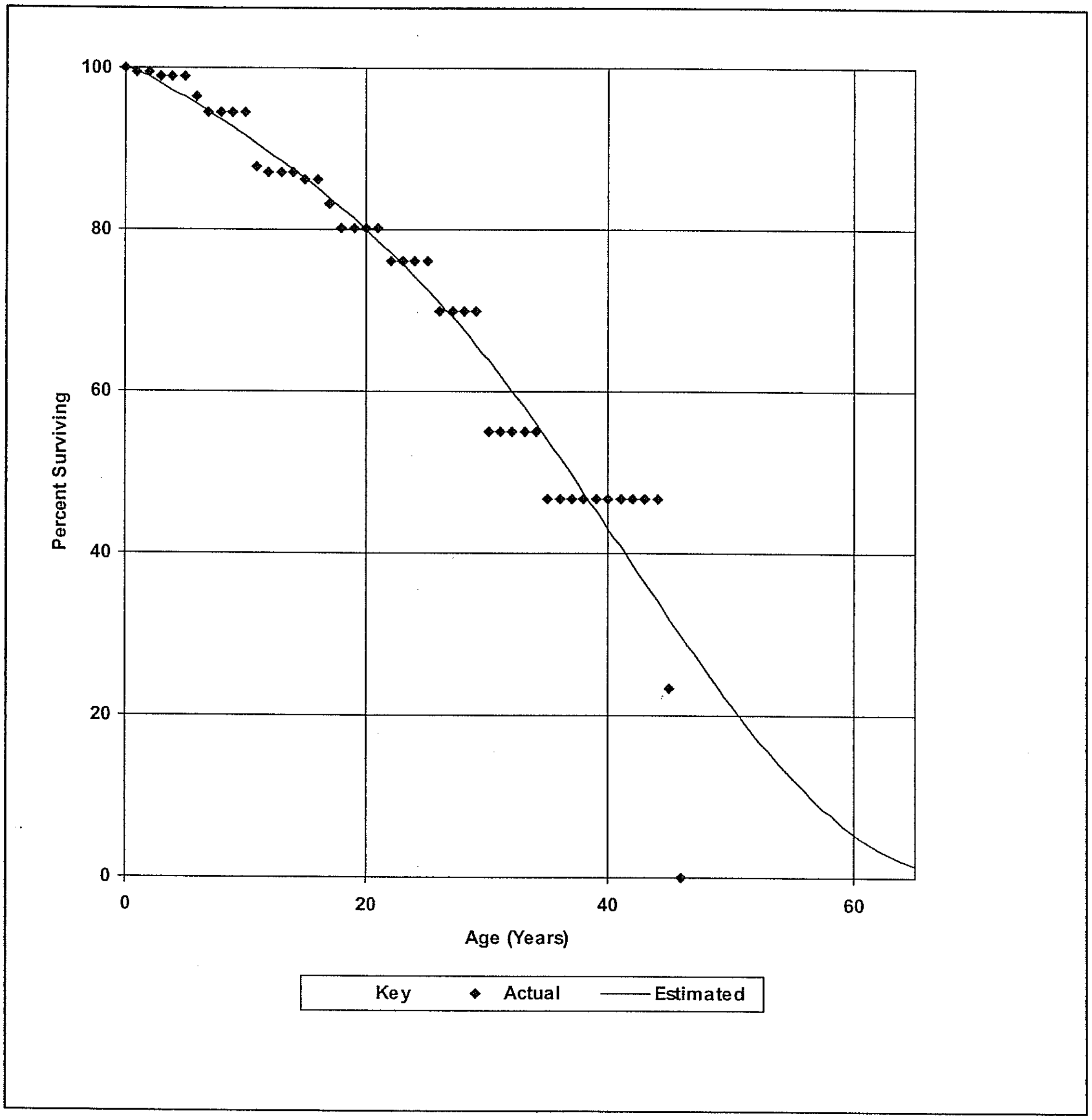
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REACTOR Reactors

T-Cut: None
Placement Band: 1966-2013
Observation Band: 2000-2013
35.0-R1

Estimated Projection Life Curve



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REGLTRN Regulating Transformers

Placement Band: 1934 - 2012
Observation Band: 1984 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	1	0	0.00000	1.00000	1.00000
0.5	1	0	0.00000	1.00000	1.00000
1.5	0	0	0.00000	1.00000	1.00000
2.5	0	0	0.00000	1.00000	1.00000
3.5	0	0	0.00000	1.00000	1.00000
4.5	0	0	0.00000	1.00000	1.00000
5.5	0	0	0.00000	1.00000	1.00000
6.5	0	0	0.00000	1.00000	1.00000
7.5	0	0	0.00000	1.00000	1.00000
8.5	0	0	0.00000	1.00000	1.00000
9.5	0	0	0.00000	1.00000	1.00000
10.5	0	0	0.00000	1.00000	1.00000
11.5	0	0	0.00000	1.00000	1.00000
12.5	0	0	0.00000	1.00000	1.00000
13.5	0	0	0.00000	1.00000	1.00000
14.5	0	0	0.00000	1.00000	1.00000
15.5	0	0	0.00000	1.00000	1.00000
16.5	4	0	0.00000	1.00000	1.00000
17.5	4	0	0.00000	1.00000	1.00000
18.5	4	0	0.00000	1.00000	1.00000
19.5	4	0	0.00000	1.00000	1.00000
20.5	4	0	0.00000	1.00000	1.00000
21.5	4	0	0.00000	1.00000	1.00000
22.5	5	0	0.00000	1.00000	1.00000
23.5	7	0	0.00000	1.00000	1.00000
24.5	13	1	0.07692	0.92308	1.00000
25.5	13	1	0.07692	0.92308	0.92308
26.5	12	0	0.00000	1.00000	0.85207
27.5	14	0	0.00000	1.00000	0.85207
28.5	16	0	0.00000	1.00000	0.85207
29.5	16	0	0.00000	1.00000	0.85207
30.5	21	3	0.14286	0.85714	0.85207
31.5	20	0	0.00000	1.00000	0.73035
32.5	21	0	0.00000	1.00000	0.73035
33.5	24	0	0.00000	1.00000	0.73035
34.5	30	3	0.10000	0.90000	0.73035
35.5	36	1	0.02778	0.97222	0.65731

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REGLTRN Regulating Transformers

Placement Band: 1934 - 2012
Observation Band: 1984 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	38	0	0.00000	1.00000	0.63905
37.5	41	0	0.00000	1.00000	0.63905
38.5	45	1	0.02222	0.97778	0.63905
39.5	44	0	0.00000	1.00000	0.62485
40.5	44	1	0.02273	0.97727	0.62485
41.5	44	3	0.06818	0.93182	0.61065
42.5	42	1	0.02381	0.97619	0.56902
43.5	41	1	0.02439	0.97561	0.55547
44.5	40	1	0.02500	0.97500	0.54192
45.5	40	0	0.00000	1.00000	0.52837
46.5	39	0	0.00000	1.00000	0.52837
47.5	39	2	0.05128	0.94872	0.52837
48.5	37	3	0.08108	0.91892	0.50128
49.5	35	3	0.08571	0.91429	0.46063
50.5	32	3	0.09375	0.90625	0.42115
51.5	29	2	0.06897	0.93103	0.38167
52.5	26	0	0.00000	1.00000	0.35534
53.5	26	0	0.00000	1.00000	0.35534
54.5	26	2	0.07692	0.92308	0.35534
55.5	23	3	0.13043	0.86957	0.32801
56.5	20	0	0.00000	1.00000	0.28523
57.5	20	1	0.05000	0.95000	0.28523
58.5	19	0	0.00000	1.00000	0.27097
59.5	19	0	0.00000	1.00000	0.27097
60.5	17	0	0.00000	1.00000	0.27097
61.5	16	1	0.06250	0.93750	0.27097
62.5	14	1	0.07143	0.92857	0.25403
63.5	12	0	0.00000	1.00000	0.23588
64.5	10	0	0.00000	1.00000	0.23588
65.5	7	1	0.14286	0.85714	0.23588
66.5	5	0	0.00000	1.00000	0.20219
67.5	3	0	0.00000	1.00000	0.20219
68.5	2	0	0.00000	1.00000	0.20219
69.5	2	0	0.00000	1.00000	0.20219
70.5	2	0	0.00000	1.00000	0.20219
71.5	1	0	0.00000	1.00000	0.20219
72.5	0	0	0.00000	1.00000	0.20219

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REGLTRN Regulating Transformers

T-Cut: None
Placement Band: 1934-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1984-1988	96.0	92.6	L2 *	3.23	174.2	R2 *	2.97	102.0	O4 *	42.54
1985-1989	94.1	129.0	R0.5	5.73	185.3	R4 *	1.64	185.3	R4 *	1.67
1986-1990	66.1	58.4	O4 *	46.65	134.0	SC *	6.74	50.6	R2 *	6.16
1987-1991	56.1	54.2	O4 *	44.63	117.8	SC *	9.77	49.7	R2 *	5.64
1988-1992	40.7	22.1	O4 *	53.35	26.2	O4 *	50.09	42.8	L1.5 *	4.81
1989-1993	26.9	8.5	O4 *	56.79	4.2	O4	61.71	26.6	L1.5 *	23.53
1990-1994	18.2	3.6	O4 *	60.74	2.4	O3 *	63.12	27.0	L3 *	17.96
1991-1995	25.4	5.2	O4 *	59.94	2.9	O3 *	63.65	1.9	O3 *	65.55
1992-1996	0.0	11.5	O4 *	48.69	0.6	O3	66.60	15.9	L3 *	40.80
1993-1997	0.0	16.5	O3	41.17	0.6	L0	69.56	31.6	L3 *	14.96
1994-1998	0.0	28.4	O2	31.19	0.7	O2	76.37	39.8	L4 *	10.54
1995-1999	0.0	51.8	L5 *	5.82	1.4	O3	83.32	47.0	S3 *	10.65
1996-2000	0.0	52.8	L5 *	7.61	1.2	O3	83.58	47.3	S3 *	10.77
1997-2001	40.9	44.5	L2 *	20.29	97.9	O3 *	5.45	0.8	O3 *	85.88
1998-2002	77.1	65.0	S3 *	8.06	135.8	SC *	8.54	0.3	SC *	95.56
1999-2003	64.2	58.9	S3 *	11.26	114.0	O3 *	11.10	0.3	SC *	93.72
2000-2004	60.6	61.5	S3 *	8.27	120.8	SC *	6.63	0.3	S0.5 *	92.55
2001-2005	55.0	53.4	L2 *	20.50	119.3	SC *	6.01	0.6	O2 *	90.52
2002-2006	32.9	38.3	L0.5	34.25	97.5	O3 *	5.95	0.5	O3 *	86.99
2003-2007	27.7	16.3	O3	63.86	90.8	O3 *	6.47	92.0	O3 *	6.21
2004-2008	10.1	2.9	O4	74.87	64.3	O3 *	6.21	50.1	L4 *	5.97
2005-2009	12.8	2.6	O4 *	75.08	59.2	O3 *	11.12	50.5	L4 *	5.59
2006-2010	7.1	1.3	O4 *	76.21	41.0	L4 *	23.42	46.9	L5 *	6.22
2007-2011	11.1	2.2	O4 *	74.75	0.5	O3	77.27	38.3	L5 *	23.53
2008-2012	10.8	1.3	O4 *	75.49	0.3	S0.5	77.12	0.3	SC	77.21
2009-2013	36.0	28.2	O4	53.47	48.5	O4 *	41.06	24.8	O2 *	56.22

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REGLTRN Regulating Transformers

T-Cut: None

Placement Band: 1934-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1984-2013	20.2	39.8	L0	15.94	57.7	L1.5 *	3.34	39.1	O4 *	31.94
1986-2013	14.2	31.8	O3	20.10	42.6	O2 *	10.83	27.1	O4 *	35.59
1988-2013	9.3	21.6	O3	29.72	21.9	O3	29.26	17.3	O4 *	39.44
1990-2013	8.4	14.6	O4 *	39.77	10.2	O4	45.10	9.3	O4 *	47.24
1992-2013	8.9	13.5	O4 *	42.02	11.7	O4	43.90	10.0	O4 *	47.69
1994-2013	16.6	14.4	O4 *	53.63	48.2	O3 *	19.88	45.1	O3 *	23.58
1996-2013	23.7	19.6	O3	53.86	68.8	O3 *	12.29	80.4	O3 *	4.99
1998-2013	32.4	21.0	O3	56.39	77.9	O3 *	14.50	93.6	O3 *	5.15
2000-2013	29.7	16.6	O4 *	61.78	67.2	O3 *	20.65	85.2	O3 *	8.74
2002-2013	17.6	8.8	O4 *	66.90	44.9	O3 *	30.63	57.6	O3 *	20.09
2004-2013	9.5	5.3	O4 *	69.10	26.1	L1.5 *	44.17	25.4	L1.5 *	45.02
2006-2013	8.8	3.6	O4	71.42	16.0	L0.5 *	55.34	13.8	L1.5 *	58.95
2008-2013	12.7	3.0	O4 *	72.57	9.5	O2 *	63.79	7.5	L1.5	67.87
2010-2013	35.0	18.6	O4 *	63.34	33.1	O3 *	51.46	19.6	L0.5 *	62.80
2012-2013	100.0				No Retirements					

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REGLTRN Regulating Transformers

T-Cut: None
Placement Band: 1934-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1984-1985	85.7	62.4	L3 *	5.35	60.6	S2 *	5.42	21.0	O4 *	80.63
1984-1987	94.7	82.6	S1.5 *	3.81	149.4	SC *	3.64	76.7	O4 *	54.32
1984-1989	92.7	86.9	L2 *	4.90	175.4	R2 *	3.64	138.3	SC *	22.09
1984-1991	68.0	75.2	O4	22.58	147.6	SC *	3.36	58.9	R2 *	3.71
1984-1993	59.3	63.4	O4 *	35.87	92.9	O4 *	20.34	51.8	S0.5 *	5.62
1984-1995	52.6	46.9	O4 *	42.43	103.6	O4 *	9.10	52.1	S0 *	3.94
1984-1997	0.0	48.1	L2 *	5.11	10.3	O4	59.94	43.1	S1.5 *	5.49
1984-1999	0.0	49.3	L2 *	4.50	10.7	O4	59.59	43.6	S1.5 *	5.37
1984-2001	0.0	48.7	L2 *	4.93	14.3	O4	54.31	44.6	S1.5 *	4.79
1984-2003	14.9	48.6	L1.5 *	4.52	17.8	O4	49.12	45.3	S1 *	4.16
1984-2005	20.3	47.3	L1.5 *	6.30	24.3	O4	38.58	45.0	S0.5 *	5.86
1984-2007	22.7	47.6	L1.5 *	5.25	30.8	O3	28.34	24.6	O4 *	39.12
1984-2009	23.7	42.5	L0.5	11.94	49.0	L1.5 *	5.11	17.6	O4 *	54.82
1984-2011	17.0	44.6	L1 *	8.19	43.9	L1	9.11	25.3	O4 *	43.41
1984-2013	20.2	39.8	L0	15.94	57.7	L1.5 *	3.34	39.1	O4 *	31.94

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REGLTRN Regulating Transformers

T-Cut: None

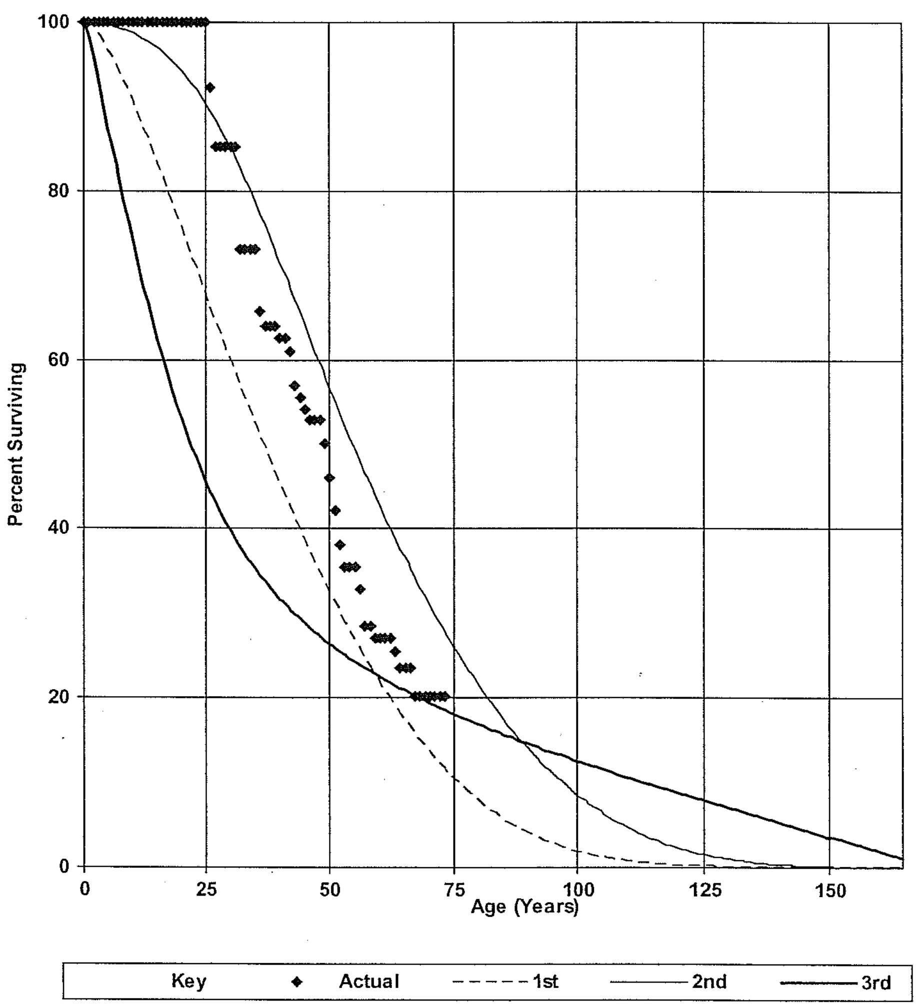
Placement Band: 1934-2012 Observation Band: 1984-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 39.8-L0 2nd: 57.7-L1.5 3rd: 39.1-O4



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Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: REGLTRN Regulating Transformers

T-Cut: None

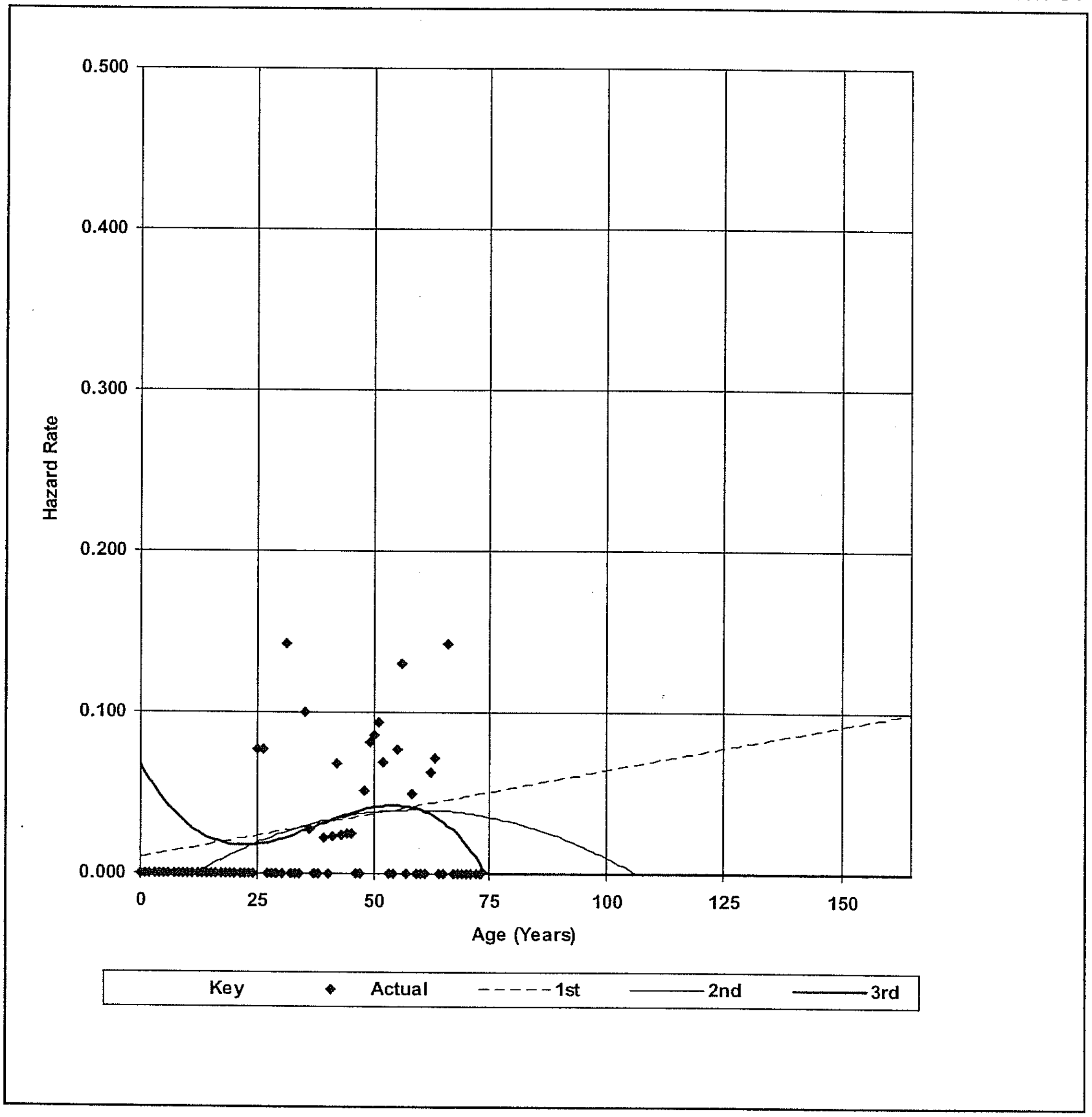
Placement Band: 1934-2012 Observation Band: 1984-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 39.8-L0 2nd: 57.7-L1.5 3rd: 39.1-O4

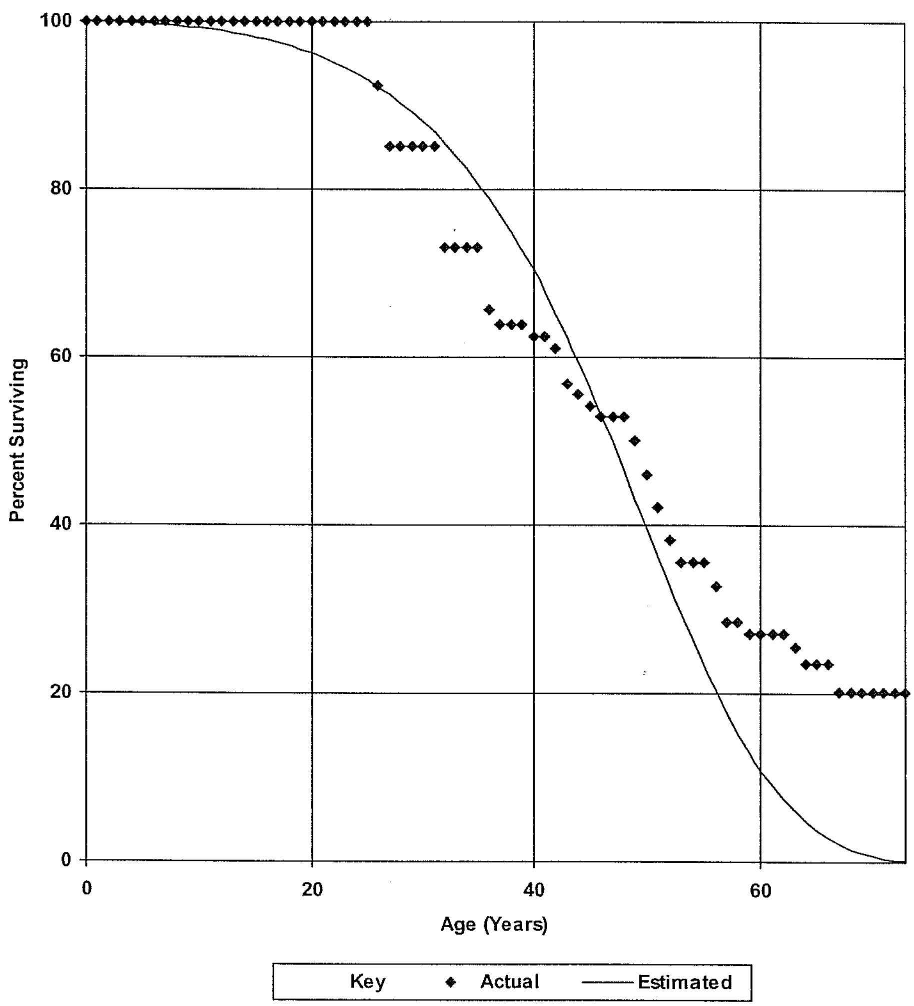


Schedule E

HYDRO ONE NETWORKS INC.
Transmission Stations
Account: REGLTRN Regulating Transformers

T-Cut: None
Placement Band: 1934-2012
Observation Band: 1984-2013
45.0-R3

Estimated Projection Life Curve



HYDRO ONE NETWORKS INC.

Transmission Stations

Account: SWITCHX Switches

Placement Band: 1926 - 2013
Observation Band: 1991 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
0.0	7,740	53	0.00685	0.99315	1.00000
0.5	7,081	90	0.01271	0.98729	0.99315
1.5	6,196	72	0.01162	0.98838	0.98053
2.5	5,628	68	0.01208	0.98792	0.96914
3.5	4,672	172	0.03682	0.96318	0.95743
4.5	3,830	112	0.02924	0.97076	0.92218
5.5	3,306	74	0.02238	0.97762	0.89521
6.5	2,620	32	0.01221	0.98779	0.87517
7.5	2,375	108	0.04547	0.95453	0.86448
8.5	1,978	29	0.01466	0.98534	0.82517
9.5	1,689	21	0.01243	0.98757	0.81307
10.5	1,432	12	0.00838	0.99162	0.80297
11.5	1,314	37	0.02816	0.97184	0.79624
12.5	1,208	13	0.01076	0.98924	0.77382
13.5	1,173	9	0.00767	0.99233	0.76549
14.5	1,151	10	0.00869	0.99131	0.75961
15.5	1,123	6	0.00534	0.99466	0.75302
16.5	1,086	2	0.00184	0.99816	0.74899
17.5	1,083	0	0.00000	1.00000	0.74761
18.5	1,087	3	0.00276	0.99724	0.74761
19.5	1,048	4	0.00382	0.99618	0.74555
20.5	1,044	11	0.01054	0.98946	0.74270
21.5	887	21	0.02368	0.97632	0.73488
22.5	802	4	0.00499	0.99501	0.71748
23.5	449	0	0.00000	1.00000	0.71390
24.5	404	0	0.00000	1.00000	0.71390
25.5	314	0	0.00000	1.00000	0.71390
26.5	311	1	0.00322	0.99678	0.71390
27.5	254	4	0.01575	0.98425	0.71161
28.5	71	0	0.00000	1.00000	0.70040
29.5	71	0	0.00000	1.00000	0.70040
30.5	22	0	0.00000	1.00000	0.70040
31.5	18	0	0.00000	1.00000	0.70040
32.5	18	0	0.00000	1.00000	0.70040
33.5	18	0	0.00000	1.00000	0.70040
34.5	18	2	0.11111	0.88889	0.70040
35.5	16	0	0.00000	1.00000	0.62258

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: SWITCHX Switches

Placement Band: 1926 - 2013
Observation Band: 1991 - 2013

Observed Life Table

Age at Beginning of Interval	Exposures	Retirements	Conditional Proportion Retired	Conditional Proportion Surviving	Cumulative Proportion Surviving
A	B	C	D=C/B	E=1-D	F
36.5	45	2	0.04444	0.95556	0.62258
37.5	50	0	0.00000	1.00000	0.59491
38.5	50	0	0.00000	1.00000	0.59491
39.5	50	4	0.08000	0.92000	0.59491
40.5	48	2	0.04167	0.95833	0.54731
41.5	42	0	0.00000	1.00000	0.52451
42.5	42	29	0.69048	0.30952	0.52451
43.5	13	2	0.15385	0.84615	0.16235
44.5	11	2	0.18182	0.81818	0.13737
45.5	9	0	0.00000	1.00000	0.11239
46.5	9	0	0.00000	1.00000	0.11239
47.5	9	0	0.00000	1.00000	0.11239
48.5	9	0	0.00000	1.00000	0.11239
49.5	9	0	0.00000	1.00000	0.11239
50.5	9	0	0.00000	1.00000	0.11239
51.5	9	0	0.00000	1.00000	0.11239
52.5	9	0	0.00000	1.00000	0.11239
53.5	9	0	0.00000	1.00000	0.11239
54.5	9	0	0.00000	1.00000	0.11239
55.5	9	0	0.00000	1.00000	0.11239
56.5	9	0	0.00000	1.00000	0.11239
57.5	9	0	0.00000	1.00000	0.11239
58.5	9	0	0.00000	1.00000	0.11239
59.5	9	0	0.00000	1.00000	0.11239
60.5	0	0	0.00000	1.00000	0.11239
61.5	0	0	0.00000	1.00000	0.11239
62.5	0	0	0.00000	1.00000	0.11239
63.5	0	0	0.00000	1.00000	0.11239
64.5	14	14	1.00000	0.00000	0.11239
65.5	0	0	0.00000	1.00000	0.00000

Schedule B1

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: SWITCHX Switches

T-Cut: None
Placement Band: 1926-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1991-1995	0.0	29.4	L2 *	38.66	38.9	R4 *	19.99	46.3	S5 *	14.58
1992-1996	0.0	89.7	L1	13.95	61.3	S3 *	12.86	50.9	S5 *	12.27
1993-1997	0.0	26.1	L2 *	28.88	31.8	S3 *	20.60	40.1	R5 *	18.33
1994-1998	10.9	26.0	L2 *	23.81	30.9	R3 *	18.90	38.3	R5 *	21.70
1995-1999	5.8	25.7	S1.5 *	14.70	29.7	S3 *	18.99	32.0	S3 *	22.34
1996-2000	4.7	26.1	L3 *	14.94	29.1	S3 *	20.88	27.9	R3 *	18.97
1997-2001	0.0	26.5	L3 *	14.92	27.7	R2.5 *	20.26	24.2	R2.5 *	15.33
1998-2002	45.7	185.7	R4 *	35.13	61.5	R3 *	33.07	124.7	SC *	19.42
1999-2003	0.0	181.2	R4 *	67.82	60.8	R2.5 *	66.11	132.0	SC *	54.68
2000-2004	91.9	179.0	R3 *	2.06	67.2	R2.5 *	2.51	159.9	R1 *	7.29
2001-2005	60.1	155.9	R0.5 *	16.77	137.3	R1 *	17.63	48.4	R1.5 *	16.10
2002-2006	59.5	157.7	R0.5 *	18.46	158.9	R1 *	18.98	48.4	R1.5 *	16.48
2003-2007	31.0	147.3	SC *	28.37	149.3	SC *	29.12	46.6	R1 *	27.69
2004-2008	27.1	125.7	SC *	26.13	134.0	SC *	28.34	40.8	SC *	24.38
2005-2009	29.2	116.8	SC *	20.95	119.3	SC *	21.63	35.1	SC *	15.04
2006-2010	19.2	124.2	SC *	23.71	127.1	SC *	24.72	39.9	SC *	21.36
2007-2011	17.7	117.7	SC *	22.76	125.3	SC *	25.23	41.4	SC *	23.16
2008-2012	23.5	120.9	SC *	21.57	124.6	SC *	22.71	42.9	SC *	20.71
2009-2013	0.0	93.7	O4 *	23.79	104.3	O4 *	26.96	37.7	SC *	26.20

Schedule B2

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: SWITCHX Switches

T-Cut: None
Placement Band: 1926-2013
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1991-2013	0.0	47.5	O3	15.52	32.9	R0.5	8.51	35.4	R0.5	9.25
1993-2013	10.2	83.5	O4 *	19.49	36.3	SC	10.54	36.4	R0.5	11.44
1995-2013	6.2	86.1	O4 *	21.72	35.4	SC	11.82	35.7	SC	13.02
1997-2013	1.4	89.2	O4 *	24.35	34.9	SC	14.14	35.3	SC	15.71
1999-2013	0.0	123.1	SC *	32.32	124.9	SC *	32.84	43.7	SC *	31.95
2001-2013	0.0	119.0	SC *	31.12	122.2	SC *	32.17	42.2	SC *	30.92
2003-2013	0.0	111.4	O4 *	28.85	117.6	SC *	30.99	40.4	SC *	29.48
2005-2013	0.0	101.4	O4 *	26.40	111.3	O4 *	29.63	38.3	SC *	27.92
2007-2013	0.0	95.4	O4 *	25.25	107.1	O4 *	28.77	37.9	SC *	27.75
2009-2013	0.0	93.7	O4 *	23.79	104.3	O4 *	26.96	37.7	SC *	26.20
2011-2013	0.0	65.6	O4 *	19.27	95.1	O4 *	24.24	36.9	SC *	24.91
2013-2013	0.0	25.1	O3	10.48	54.7	O4 *	14.34	24.3	O4 *	15.41

Schedule B3

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: SWITCHX Switches

T-Cut: None

Placement Band: 1926-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1991-1992	0.0	21.4	L2 *	74.72	38.2	R4 *	56.78	45.8	S5 *	47.74
1991-1994	0.0	27.5	L2 *	66.75	38.9	R4 *	55.24	46.3	R5 *	46.86
1991-1996	0.0	32.1	L2 *	34.77	39.4	R4 *	19.22	46.7	S5 *	15.45
1991-1998	0.0	25.7	L2 *	29.02	33.5	R4 *	19.40	40.5	R5 *	14.79
1991-2000	0.0	28.0	L2 *	21.53	33.3	R3 *	17.20	41.0	R5 *	16.63
1991-2002	0.0	31.0	L2 *	15.98	33.7	R3 *	15.86	41.2	R5 *	17.10
1991-2004	0.0	34.6	L2 *	19.79	34.4	R3 *	19.84	41.5	R4 *	11.89
1991-2006	0.0	37.4	L1.5 *	18.69	34.3	R2.5 *	20.76	40.7	R4 *	11.23
1991-2008	0.0	39.2	L1	13.41	33.8	R2	14.38	39.3	R2.5 *	9.40
1991-2010	0.0	44.3	O2	14.53	33.7	R1.5	10.97	37.9	R1.5 *	9.69
1991-2012	0.0	50.4	O2	15.55	34.6	R1.5	8.83	37.5	R1.5	9.42
1991-2013	0.0	47.5	O3	15.52	32.9	R0.5	8.51	35.4	R0.5	9.25

Schedule C

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: SWITCHX Switches

T-Cut: None

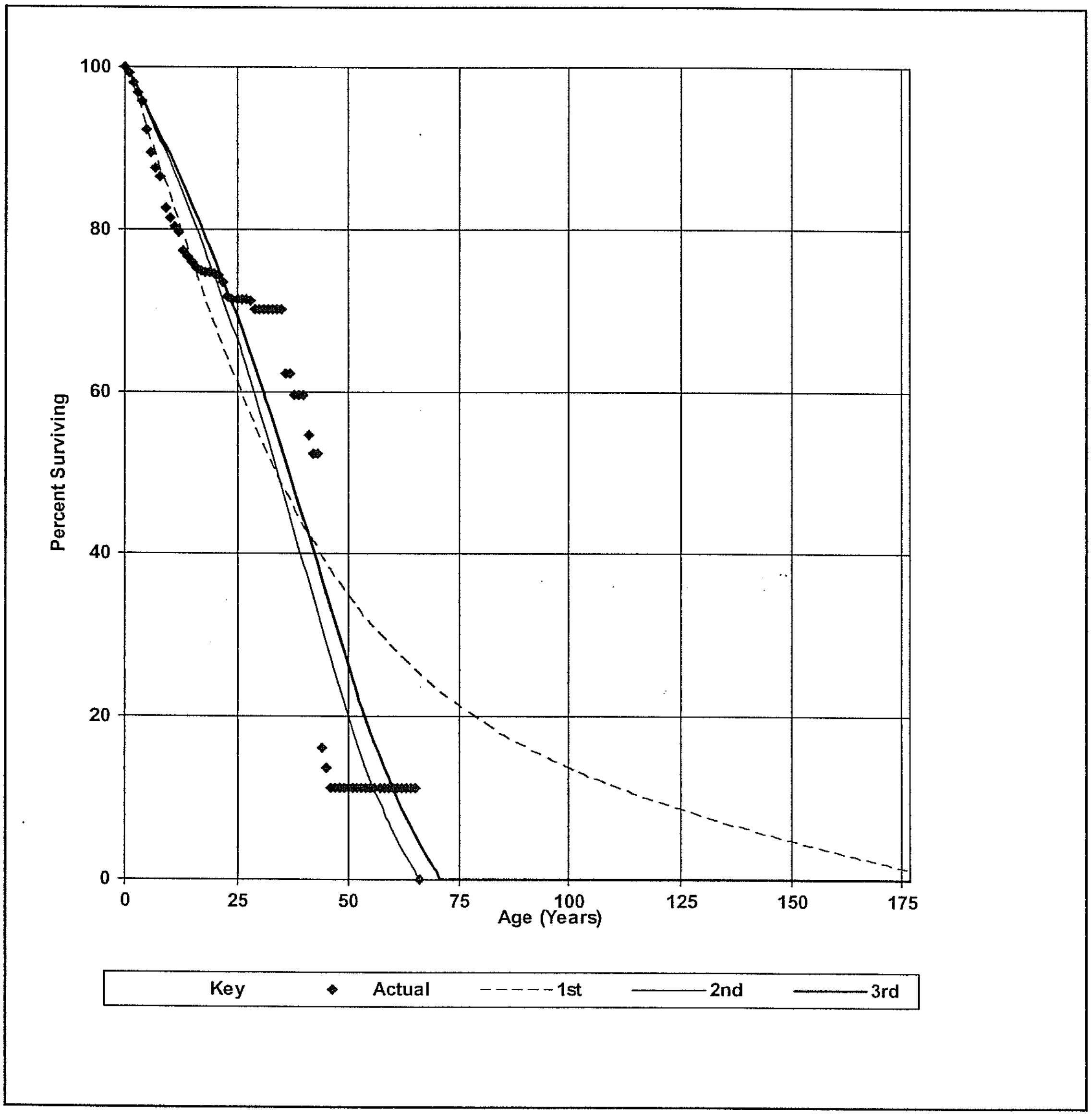
Placement Band: 1926-2013 Observation Band: 1991-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 47.5-O3 2nd: 32.9-R0.5 3rd: 35.4-R0.5



Schedule D

HYDRO ONE NETWORKS INC.

Transmission Stations

Account: SWITCHX Switches

T-Cut: None

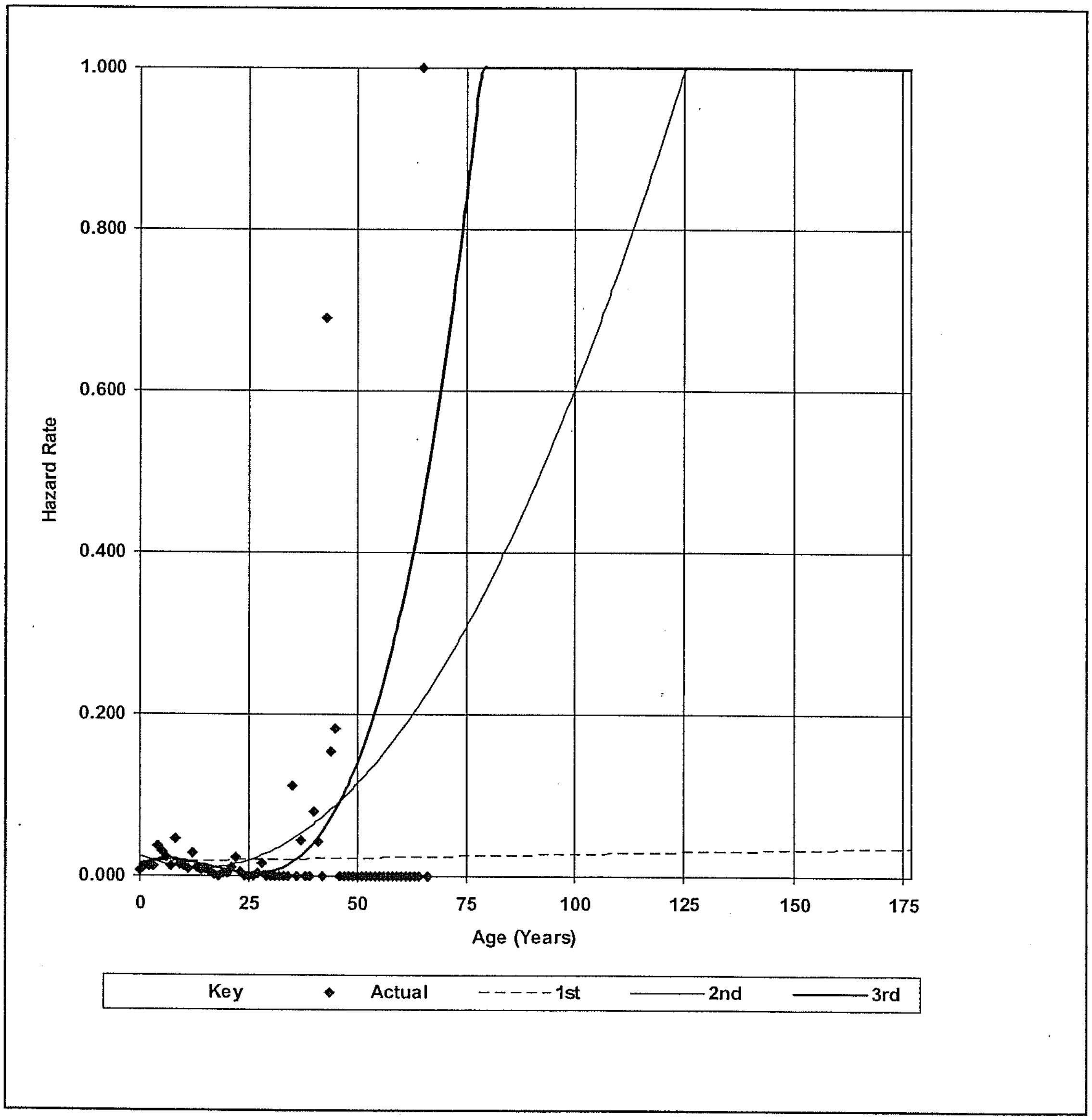
Placement Band: 1926-2013 Observation Band: 1991-2013

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 47.5-O3 2nd: 32.9-R0.5 3rd: 35.4-R0.5



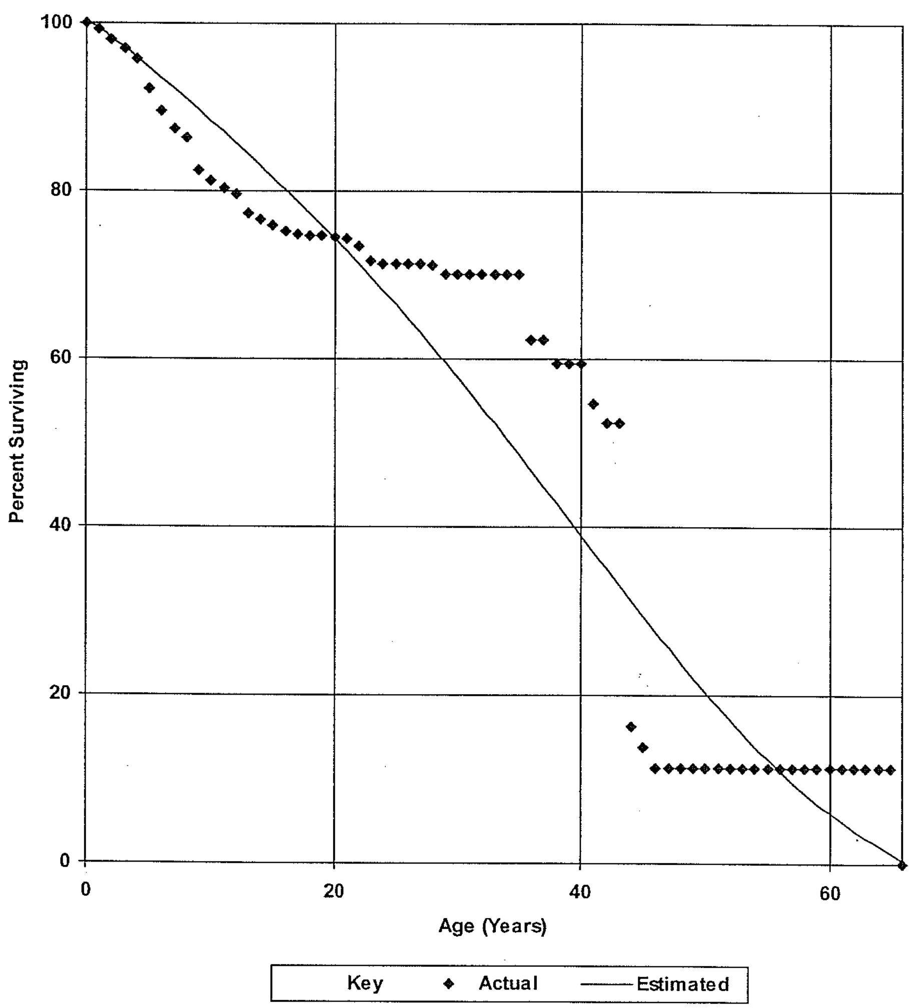
HYDRO ONE NETWORKS INC.

Transmission Stations

Account: SWITCHX Switches

T-Cut: None
Placement Band: 1926-2013
Observation Band: 1991-2013
33.0-R0.5

Estimated Projection Life Curve



OEB INTERROGATORY #72

Reference:

TSP-01-04-13 p. 29

Interrogatory:

At the above noted reference, METSCO stated the following:

For clarity, METSCO understands that the RRM analysis only takes place after the AM decision-making processes – including the use of AA and ARA capabilities – has been completed.

a) Please confirm that the referenced statement is correct.

    i. If not, please define where the RRM analysis takes place in the AM decision making process, specifically where it takes place relative to the AA and ARA.

Response:

a) The RRM was previously used as a simplified method to communicate risk to customers and stakeholders following the development of an investment plan as per the process defined in TSP Section 2.1. A summary of the RRM is detailed in TSP Section 1.3, Attachment 4.

Witness: Donna Jablonsky

OEB INTERROGATORY #73

Reference:

TSP-01-04-13 p. 30-32

Interrogatory:

At the first reference above, METSCO stated the following:

Note that the definition of “risk” underlying this particular criterion of our assessment framework carries a particular meaning, consistent with the ISO 5500x asset management frameworks referenced in the criterion’s definition.

In this context, the notion “risk” entails a single quantifiable number that combines the quantitative expressions of probability (%) and impact of an asset’s failure expressed in numerical terms (e.g. outage impact that may be expressed in monetary terms) as a multiplication between the two parameters. Such an expression of risk (or risk costs) is considered to be an asset management best practice since it captures both likelihood and consequence of failure in a single numerical value – making prioritization across individual assets, asset classes, or intervention options both simpler and more transparent.

At the second reference above, METSCO stated the following:

While all of these risk-related factors are ultimately present in the expression of the final Composite Risk Score and individual Sub-Indices, at no point in the calculation process is risk explicitly expressed as Failure Probability × Failure Impact. Importantly, the fact that Hydro One’s framework does not utilize the more commonly adopted expression of risk associated with leading technical standards, only implies than the manifestation of the relationship between the quantitative probability and impact related elements of the Hydro One AA approach is less clear and more complex (in light of the presence of multiple other factors in the calculation of the index) than it otherwise could be.

At the third reference above, METSCO stated the following:

the comparison of AA outputs – expressed as non-dollar indices – with the risk definitions established through other ARA inputs, is more complicated, and less intuitive than it could have been had all units were defined in numerical (preferably monetary) terms, as outcomes of Probability × Impact calculation. This representation of risk implies that the criteria comprising the assessment of asset failure Probability are clearly separated from the criteria comprising the Impact assessment if the asset failure occurs.

At the fourth reference above, METSCO stated the following:

Modest incremental adjustments to the AA framework to clearly define asset probability and impact would place the utility within the best practice utilities.
Based on our findings, METSCO provides the following recommendation:

- Consider clearly separating the risk factors/criteria in AA to define probability of failure of a specific asset, and the impact of asset failure to explicitly assess a broader variety of outage consequence costs, such as utility's and socioeconomic costs, including the costs associated with the environment, safety/collateral damages, environment, customer interruption costs and financial impacts.

a) Please confirm that the following METSCO statement is materially correct: "*the notion "risk" entails a single quantifiable number that combines the quantitative expressions of probability (%) and impact of an asset's failure expressed in numerical terms (e.g. outage impact that may be expressed in monetary terms) as a multiplication between the two parameters. Such an expression of risk (or risk costs) is considered to be an asset management best practice since it captures both likelihood and consequence of failure in a single numerical value – making prioritization across individual assets, asset classes, or intervention options both simpler and more transparent*".
    i. If not, why not.

b) Does Hydro One agree that its approach to defining risk "is more complicated, and less intuitive than it could have been"?

c) Does Hydro One intend to make the "Modest incremental adjustments to the AA framework to clearly define asset probability and impact would place the utility within the best practice utilities."
d) If yes, please describe the plan (scope, schedule and budget) Hydro One will be implementing to adopt best practice.

e) Please quantify, in terms of standard deviations from Expected Direct Impact, where Worst Reasonable Direct Impact lies on the probability continuum between Expected Direct Impact and Worst Possible Direct Impact.

f) Please confirm that the probability of failure curves for Hydro One's assets are developed on an Expected Direct Impact basis (i.e. not a Worst Reasonable Direct Impact basis.

   i. If not confirmed, please describe the basis upon which the probability of failure curves are developed and how they relate to Worst Reasonable Direct Impact events.
   ii. If confirmed, please explain how Hydro One translates from an Expected Direct Impact probability curve to a Worst Reasonable Direct Impact probability curve.
   iii. If Hydro One does not translate between expected and worst reasonable probability curves, please explain how this avoids creating a systematic bias in evaluating risk.

<u>Response:</u>

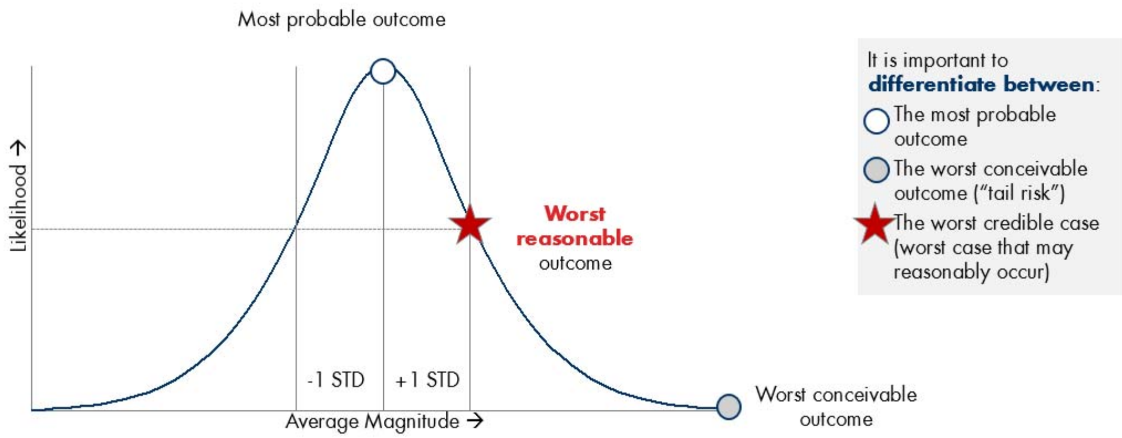
a) Hydro One confirms that the above METSCO statement is materially correct. Hydro One's Asset Risk Assessment ("ARA") process, detailed in TSP Section 2.1.2.3, evaluates multiple criteria to ultimately determine individual asset needs. The ARA process expands on the traditional risk definition of probability x consequence to enable the assessment of multiple factors, including load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations to ensure capital expenditures target the most appropriate mix of assets and incorporate customer needs and preferences. The output of the ARA process are potential candidate investments that are put forth for further consideration during the Investment Planning Process, and the ARA establishes the necessary fact base to assess the probability and consequence of safety, reliability and environmental risks at the scoring stage of the Investment Planning Process. It is during the scoring stage that the traditional definition of risk, in alignment to METSCO's statement above, is applied to the safety, environmental, and reliability risk mitigated by a particular investment to enable calibrated prioritization and optimization of the portfolio of investments.

b) No. This level of complexity is necessary for a more comprehensive assessment.

c) No. It is more than a modest incremental adjustment.

d) Please refer to c) above.

e) From the perspective of a hypothetical risk distribution curve, the worst reasonable outcome would lie approximately 1 standard deviation away from the most probable outcome, as shown in the illustrative example below:



f) Confirmed.

i. N/A

ii. Hydro One subsequently applies a modifier to translate from the most probably outcome to the worst reasonable outcome – for example, if there is a certain set of coincident circumstances required for a worst reasonable outcome to materialize, the joint likelihood of the triggering event and coincident event is used.

iii. N/A

OEB INTERROGATORY #74

Reference:

TSP-01-04-13 p. 42

Interrogatory:

At the above noted reference, METSCO stated the following:

The Criticality evaluation category assigns a criticality score to the evaluated power transformer based upon the station that it is installed within, the type of power transformer as well as the individual asset voltage rating, MVA rating and single point of vulnerability.

a) When evaluating transformer criticality, define the factors attributable to:
   i. The specific station
   ii. The type of power transformer
   iii. Asset voltage rating
   iv. Asset MVA rating
   v. Asset single point of vulnerability

b) For materially similar transformer capacity and voltage classes, please provide example risk assessments for the following representative transformer configurations:
   i. Transform feeding a radial circuit (i.e. non-redundant circuit)
   ii. Transformer feeding one circuit of a networked (e.g. redundant) transmission feed (i.e. one branch of a network/redundant supply)
   iii. The same transformer before and after a circuit was networked (i.e. risk evaluation before becoming networked, risk evaluation after becoming networked).

c) Repeat the above process for the following asset classes:
   i. Conductor
   ii. Breaker

Response:

In AA these are our factors that are evaluated.

a) Transformer:

i. Voltage Rating, Bulk Power System (BPS), Northeast Power Coordinating Council (NPCC), Basic Minimum Power System (BMPS), Mission Critical, Critical Customer List, Generation Supply, Interconnections, Total Customer Load, Total Station power Flow

ii. Autotransformer, Step Down, Regulator, Phase Shifter

iii. System voltage rating

iv. The unit's rated capacity

v. Single point of vulnerability is an asset that lacks redundancy

b) These parameters are used in the Criticality assessment but do not align to the example risk assessments. Therefore examples cannot be provided.

c) Conductor:

i. Voltage Level, NPCC Impactive, Generation Supply, Interconnections, Radial/Network, Single/Multi circuit, Total Customer Load, Customer Supply, Critical Customer List, Ontario Power System Restoration Plan (OPSRP), Operating Input

ii. – v) This does not apply to Conductor. Criticality is calculated at the Circuit level which is provided in i)

Breaker:

i. Voltage Rating, BPS (NPCC), BMPS, Mission Critical, Critical Customer List, Generation Supply, Inter Connections, Total Customer Load, Total Station power Flow

ii. Breaker type

iii. System voltage rating

iv. MVA Rating does not apply to breakers

v. Single point of vulnerability is an asset that lacks redundancy

OEB INTERROGATORY #75

Reference:
TSP-01-04-13 p. 44-45
Figure 7

Interrogatory:
At the above noted reference, METSCO stated the following:

Figure 7 illustrates an example of the incremental information captured in Hydro One's strategy document and collected as a part of ARA - in this case with respect to transformer oil leaks across the fleet. Oil leakage information represents a significant indicator of the overall degradation and failure of a power transformer. As such, while it is not captured in the AA score, this critical information is nevertheless integrated into the decision-making process prior to concluding asset prioritization work.

a) Are Major and Minor oil leaks an element of the condition assessment utilized in the AA process?
   i. If no, why doesn't the condition assessment for transformers include information that "represents a significant indicator of the overall degradation and failure of a power transformer"?
   ii. If yes, how does Hydro One avoid double counting the influence that oil leaks (major and minor) have on asset management decision making?

Response:
a) Yes, oil leak related information is captured in TOP UP and DR failure modes which are in the Condition Algorithm. During the work planning process, the subject matter expert assesses each of the transformers with reported oil leaks, and conducts an actual inspection on the unit to verify the severity of the oil leak prior to the actual repair work. This assessment will avoid any double counting.

OEB INTERROGATORY #76

Reference:

TSP-01-04-13 p. 45

Interrogatory:

At the above noted reference, METSCO stated the following:

These individual assessments provide an even greater granularity of information as to the current risks associated with individual asset, along with incremental justification of intervention. These information categories include:

- Demographics: Age of the evaluated asset when compared to its ESL as well as overall demographics across all power transformers.

a) Do the demographics across all power transformers influence how Hydro One evaluates the risk score associated with an individual asset?
   i. If yes, please explain how.

b) Do the demographics across all power transformers influence how Hydro One evaluates the incremental justification of intervention?
   i. If yes, please explain how.

Response:

a) No, transformer replacements are driven by asset condition, with the age of the transformer incorporated into its risk.

b) No, individual asset assessments are used to inform intervention options.

OEB INTERROGATORY #77

Reference:
TSP-01-04-13 p. 47

Interrogatory:
At the above noted reference, METSCO stated the following:

The technical assessment document concludes with a net present value (NPV) analysis, where different options (e.g. status quo, repair/refurbish, replacement) are compared and contrasted with each other, using the annual investment requirements as an input for each investment option in order to identify the preferred option that yields the lowest NPV result.

a) Please provide at least two typical technical assessment documents for each of the following asset classes:
   i. Transformers
   ii. Breakers
   iii. Conductor

Response:
a)
   i. Technical assessment reports for transformers have been provided as Attachment 1 to this response and in Interrogatory I-01-OEB-79.
   ii. Breakers assessments are carried out through Asset Analytics, NPV analysis and other factors as described Exhibit B-1-1 TSP Section 2.2 however there is no assessment report.
   iii. It is not possible to refurbish or maintain deteriorated conductor through repairs. Therefore a repair vs. replace NPV analysis is not done for this asset class.

Witness: Donna Jablonsky

Marathon T11

Transformer Assessment

Keywords: Marathon, T11, Transformer, Transmission, Station, Assessment

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REVISION HISTORY

Date	Revision	Revision Comments
Nov 2016	**0**	**Initial draft**

APPROVAL SIGNATURES

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Date:			

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

- Built in 1976 and in-service in 1977, Marathon T11 is a 75/100/125 MVA, 226-125-14.1kV, 3 phase auto transformer with 3 single phase on load tap changers.
- The T11 Transformer at Marathon TS has been reviewed and assessed based on: 1) Demographics, 2) Equipment condition, 3) Potential or existing environmental/HSE hazards, 4) Loading and 5) Economics.
- T11 oil analysis has shown acceptable internal condition.
- One of T11's bushing has shown overheating which required replacement.
- Loading on T11 is light and stable in general.
- NPV analysis concluded it is most economical to remain status quo or perform refurbishment until end of projected economic life.
- Recommend to continue normal operation, to conduct necessary maintenance and monitoring at regular intervals within the next 5 years. A re-assessment at the end of 5 year period is considered prudent.

2. Equipment Summary

Built 1976 and in-service in 1977 by Canadian General Electric (CGE), Marathon T11 is a 75/100/125 MVA, 226-125-14.1kV, 3 phase auto transformers with 3 single phase on load tap changers (Model MI) in service in 1996 by MR.

3. Demographics

T11 was in-serviced 1977 (39 years old). A total of 91 similar units are currently in service as of Dec 2015.

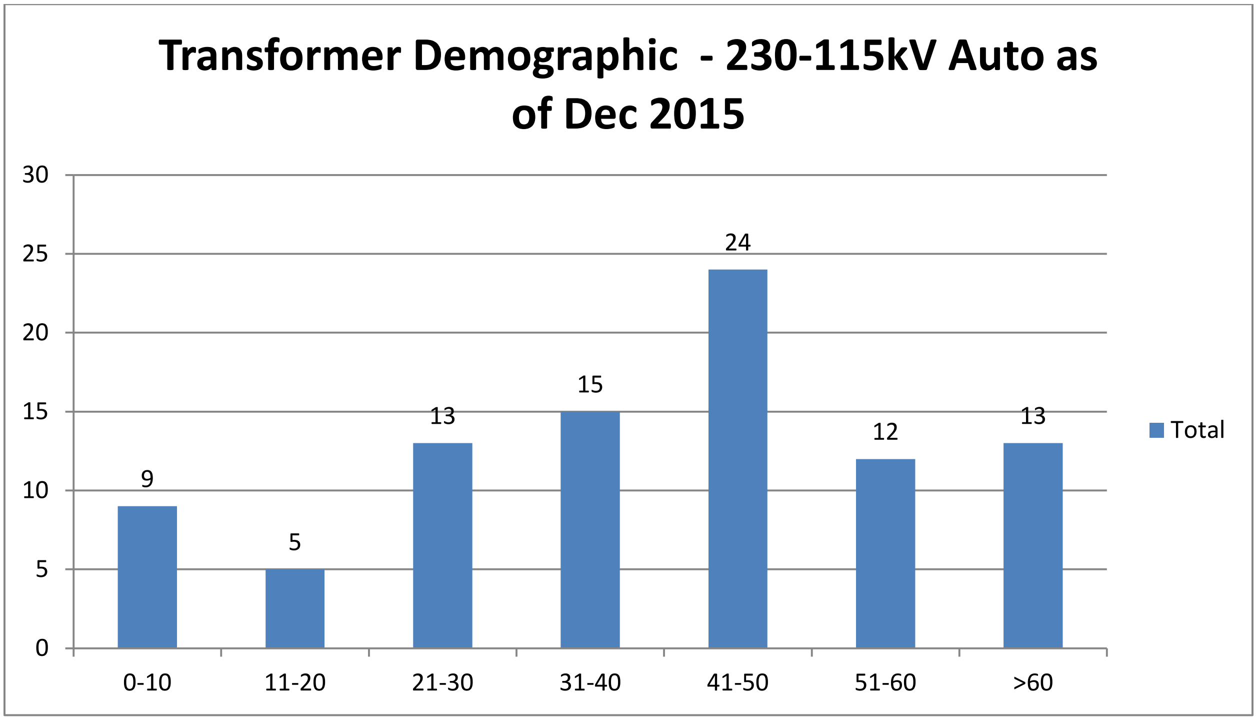


Chart 1: Transformer Demographic – 230-115kV Auto Transformer as of Dec 2015

4. Equipment Condition

Equipment condition is examined based on: 1) Dissolved Gas Analysis (DGA) and 2) Preventive Maintenance Result, Trouble Calls and Deficiency Report;

4.1 Oil analysis Data

DGA results showed minimal insulation deterioration in T11 as suggested by low Furan and satisfactory gas profile per PR1127. Acetylene (C2H2) have been detected in the past, but disappeared in recent samples, suggesting no active fault/overhearing.

T11's oil quality is acceptable.

Date	C2H2	C2H4	C2H6	CH4	CO	CO2	H2	N2	O2	Tol Gas vol (%)
08/23/2011	2	3	0	0	121	897	0	64300	30100	9.5
06/07/2012	4	4	0	0	148	886	15	72700	33300	10.66
05/16/2013	3	3	0	0	140	785	0	60500	29300	9.04
10/11/2013	3	0	0	0	159	980	0	65900	32500	9.91
05/13/2014	0	0	0	0	144	819	0	72800	33500	10.69
06/30/2014	3	4	0	0	147	874	0	63500	26100	9.03
04/30/2015	0	0	0	0	42	418	0	33600	16400	5.05
04/07/2016	0	0	0	0	86	668	20	45800	22000	6.83

Table 1: DGA results for T11 from previous years. Quantities that are beyond warning limits are underlined and highlighted in red.

Date	Acidity	Colour	Furan	IFT	kV (ASTM D1816)	kV (ASTM D877)	Moisture	pf @ 25 °C
08/23/2011	0.01	1	0	33.5	36	50	10	0.06
06/07/2012	0.01	1.5	0	32.3	64	47	6	0.05
05/16/2013	0.01	1	0	33.3	54	46	3	0.04
10/11/2013	0.01	1.5	0	33.4	54	41	2	0.04
05/13/2014	0.01	1.5	0	33.9	49	46	3	0.04
06/30/2014	0.01	1	0	34.9	49	52	9	0.07
04/30/2015	0.01	1.5	0	33.9	46	57	2	0.04
04/07/2016	0.01	1		35	64	58	6	0.04

Table 2: Marathon T11 Oil quality from previous years. Quantities that are beyond warning limits are underlined and highlighted in red.

4.2 Maintenance History, Trouble Calls and Deficiency Report

Standard power transformer maintenance packages are applied on Marathon T11 per Hydro One Work Standard Document SM-54-007 (main tank) and SM-54-047(ULTC) respectively.

Preventive Maintenance schedule and results are summarized in Table below.

Maintenance Item	2011	2012	2013	2014	2015	2016	2017
TF-GENERAL-DBT (8 year interval)	CR01				CR01		
TF-GENERAL-D1 (4 year interval)					CR02		
TF-GENERAL-D2 (8 year interval)						CR01	
TF-GENERAL-GOT (Annual)	CR02	CR01	CR01	CR01	CR01	CR01	x
UT-MR-MI-SI (R) (8 year interval)					CR01		
UT-MR-MI-SI (B) (8 year interval)					CR01		
UT-MR-MI-SI (W) (8 year interval)					CR01		
UT-MR-MI-UTOA (R) (Annual)	CR01	CR01	CR01	CR01	CR01	CR01	x
UT-MR-MI-UTOA (B) (Annual)	CR01	CR01	CR01	CR01	CR01	CR01	x
UT-MR-MI-UTOA (W) (Annual)	CR01	CR01	CR01	CR01	CR01	CR01	x

Table 3: Preventive maintenance summary of T11 and future schedule (marked by x)

A list of all Preventive maintenance results are appended in Appendix I. It is concluded that preventive maintenance are performed on time and results are acceptable.

<u>Equipment Obsolescence</u>
T11 is a CGE Transformer that uses 3 MR (Model MI) tap changers. The original manufacturer still provides parts and services to this type of tap changer. Some parts are no longer available off-the-shelf. Depending on parts required, it will require original manufacturer (MR) to fabricate on demand, with 4-6 weeks lead time.

Trouble calls/deficiency report

Lists of trouble calls/deficiency report have been reviewed and appended in Appendix II. It is concluded that defects found are repetitive and concentrates on breather issues. Highlights include:

1. Multiple Transformer breather failed alarms have been reported. Cause undetermined by field staff even though sensors and heating element has been replaced in the past. [Ref. notification : 12296081, 13460667, 13468578, 13532253, 13533644, 14489339]
2. Thermo vision reported tertiary bushings to be extremely hot. After inspections, loose connections were determined to be the cause but the overheating had damaged the bushings. Replacements were carried out for the equipment. [Ref. notification : 130338920, 13040667]
3. Oil leaks observed at diverter bleeder and H3 bushing pocket bleeder which were tightened. Oil leaks have also been observed at pipes as shown by the images in Appendix III. [Ref. notification: 12569160, 12471463, 1438032]
4. Damaged transistor underwent replacement. [Ref. notification: 10398924]

5 Potential Environmental Risk/HSE

5.1 Spill Risk Assessment

Marathon TS is ranked as low risk (Level 1) for spill containment (163 of 256) stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates [1]. Marathon T11 is not equipped with containment.

5.2 PCB content

Table below summarized the latest PCB content detected in various part of the equipment. Hydro One is obligated to remove or retrofit equipment with PCB contamination >50ppm per Environment Canada regulation by 2025.

Equipment	Description	Date	PCB (ppm)	Lab Reference
1175001	TF: Auto - 125MVA 226-125-14.1kV	4/7/2016	2	M308793A
1226373	(H0X0)- BUSHING: 15 kV	n/a	[unknown]	
1226375	(H3) - BUSHING: 196 kV	9/26/2015	2	B5J3813
1226383	(X3) - BUSHING: 115 kV	9/26/2015	28	B5J3813
1226384	(H2) - BUSHING: 196 kV	9/26/2015	28	B5J3813
1226386	(H1) - BUSHING: 196 kV	9/26/2015	28	B5J3813
1226388	(H3) - BUSHING: 196 kV	n/a	[unknown]	
1226390	(X2) - BUSHING: 115 kV	9/26/2015	31	B5J3813
1226392	(X1) - BUSHING: 115 kV	n/a	[unknown]	
1944828	(Y#) - BUSHING: 15 kV	n/a	[unknown]	
1944829	(Y#) - BUSHING: 15 kV	n/a	[unknown]	
1944830	(Y#) - BUSHING: 15 kV	n/a	[unknown]	
1223268	(HB) TF: ULTC/Filter - 230 kV Div	n/a	[unknown]	
1223270	(HR) TF: ULTC/Filter - 230 kV Div	n/a	[unknown]	
1223272	(HW) TF: ULTC/Filter - 230 kV Div	n/a	[unknown]	

Table 4: PCB Content for various equipment

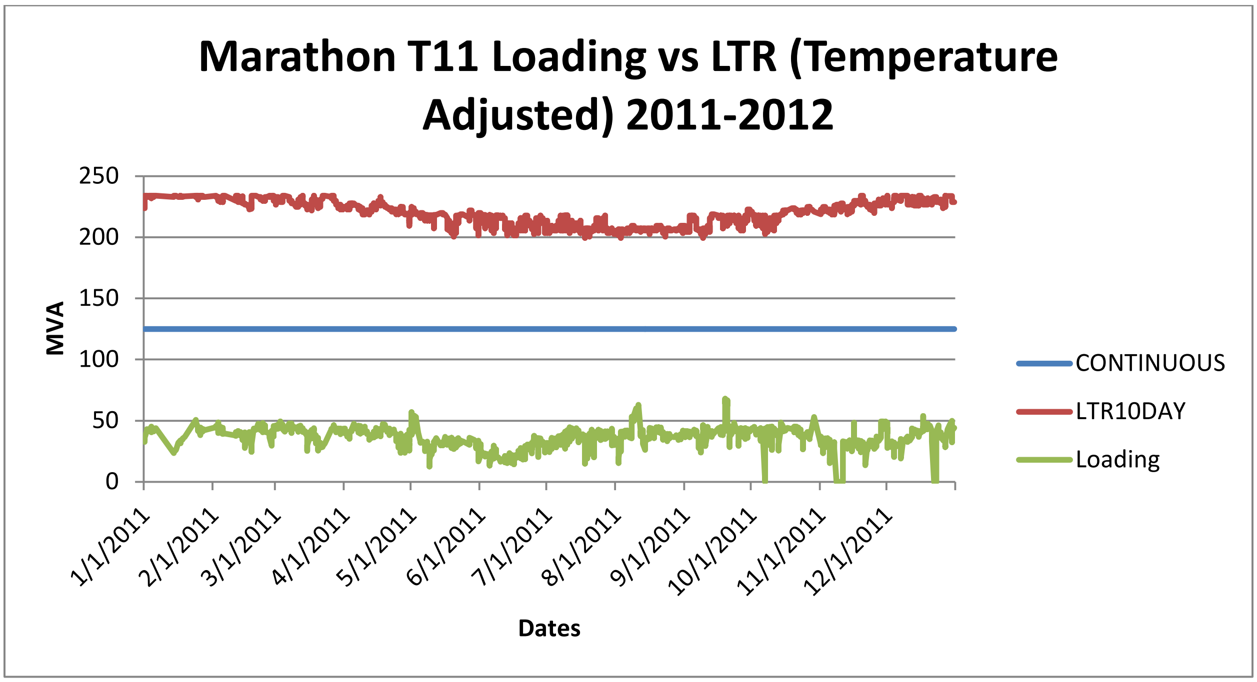
6 Equipment Loading

Marathon T11 is 75/100/125 MVA with summer and winter Limited Time Rating (LTR) stated below:

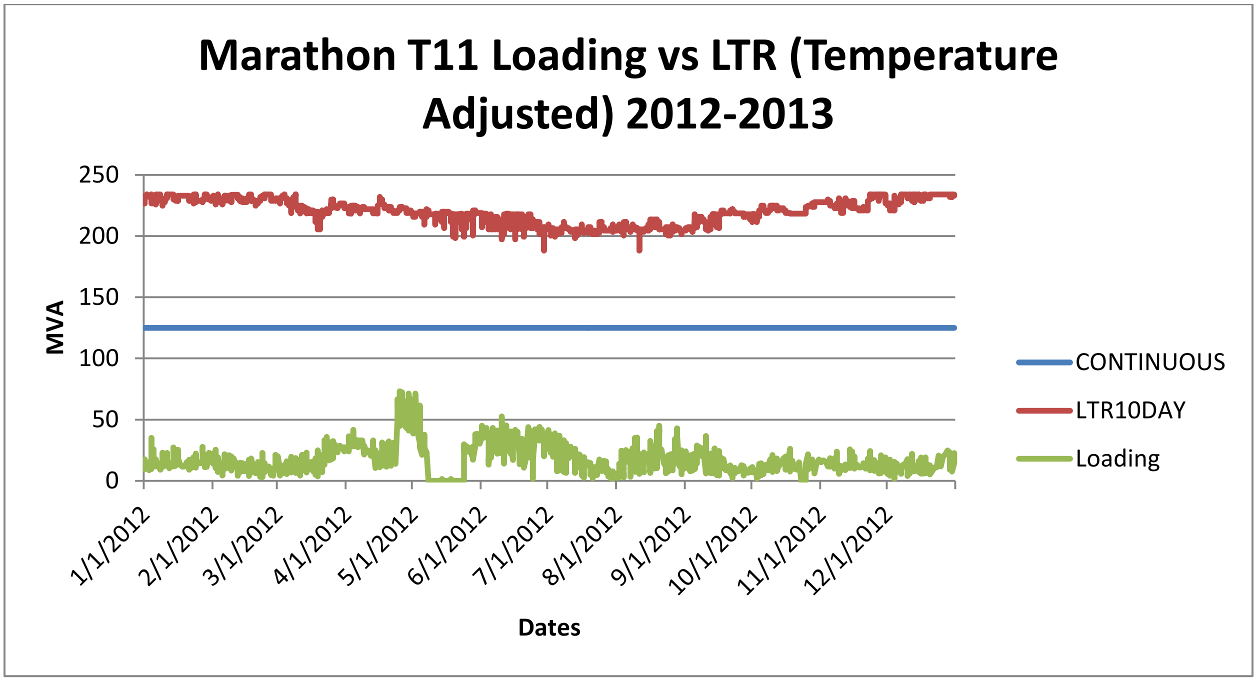
T11:

Summer 10d LTR (31 ºC)	Winter 10d LTR (5ºC)
210MVA	230MVA

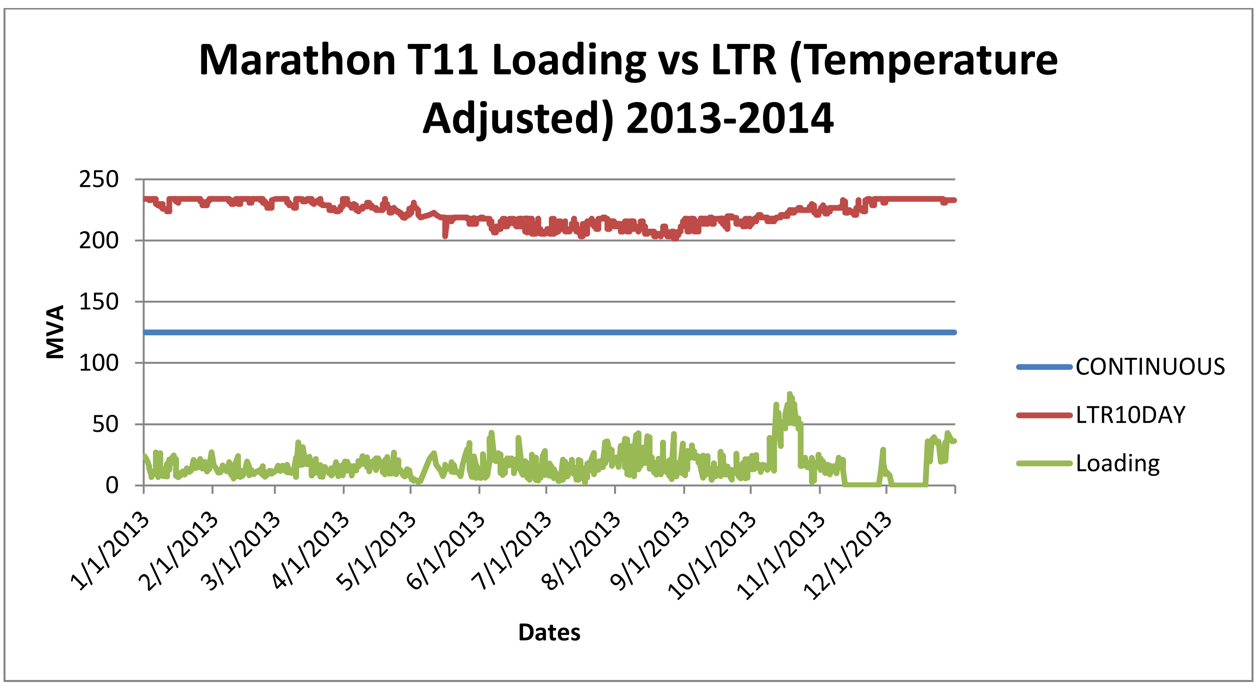
Marathon T11's loading was reviewed with respect to its temperature adjusted LTR from 2011 -2015. It is observed T11's loading is positioned well below various loading limits.



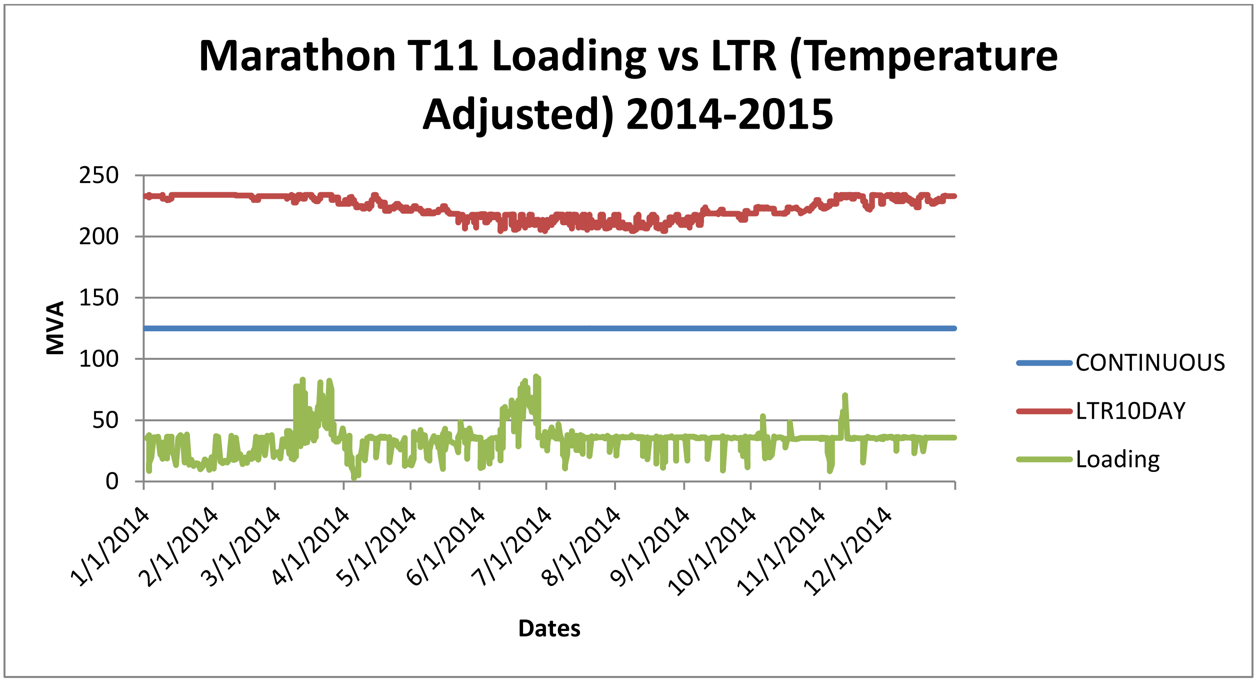
Graph 1: Marathon T11 Loading vs LTR (Temperature Adjusted) 2011-2012



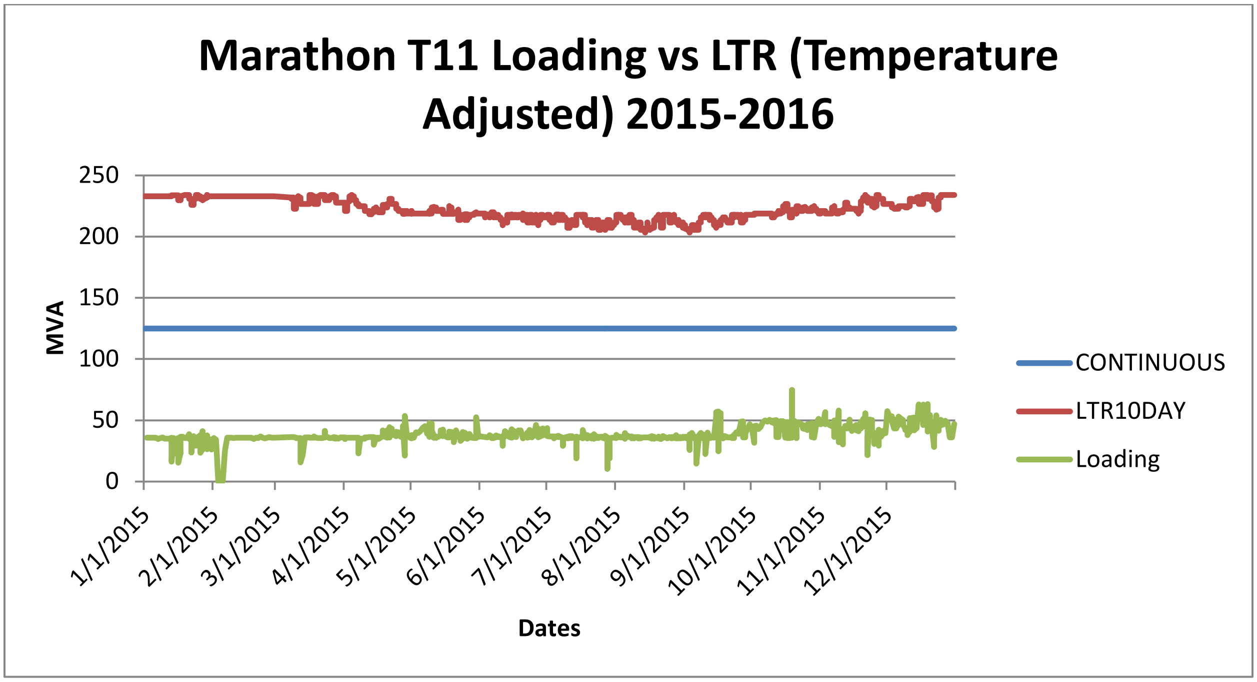
Graph 2: Marathon T11 Loading vs LTR (Temperature Adjusted) 2012-2013



Graph 3: Marathon T11 Loading vs LTR (Temperature Adjusted) 2013-2014



Graph 4: Marathon T11 Loading vs LTR (Temperature Adjusted) 2014-2015



Graph 5: Marathon T11 Loading vs LTR (Temperature Adjusted) 2015 -2016

7 Economics

7.1 Recorded OM&A Spending.

Table 4 summarized OM&A spending incurred on Marathon T11 since SAP inception in 2008. It is concluded that Preventive maintenance spending is high.

T11 has incurred higher corrective costs in 2013 and 2014 due to replacement of damaged bushings. [Ref. Notifications: 13038920, 13040667]

T11 underwent filtration system installation and has observed a higher upgrade costs in 2014. [Ref. orders: 60674582]

Year	CORR	UPGR	EMER	PREV	Grand Total
2008				$7,000.00	$7,000.00
2009	$1,650.00		$2,338.60	$5,092.00	$9,080.60
2010	$2,612.71			$11,050.39	$13,663.10
2011				$11,888.21	$11,888.21
2012	$6,989.40			$4,938.73	$11,928.13
2013	$140,450.05		$15,223.70	$638.41	$156,312.16
2014	$12,294.00	$111,457.17	$2,908.35	$872.76	$127,532.39
2015				$24,460.30	$24,460.30
2016			$4,332.28	$7,090.18	$11,422.46
Grand Total	**$275,453.44**		**$24,802.93**	**$73,030.98**	**$373,287.35**

Table 5: Historical OM&A spending on T11

PREV Maintenance Activity	Average Actual Cost (2013 - 2015)	Applicable to unit under assessment
TAP CHANGER OIL SAMPLES	$ 370.51	✓
TAP CHANGER OIL FILTER CHANGES	$ 1,115.05	✓
TAP CHANGER SI	$ 7019.4	✓
TRANSFORMER DBT --General	$ 5,660.90	✓
TRANSFORMER D1 --General	$ 3,862.40	✓
TRANSFORMER D2 --General	$ 3,517.07	✓
TRANSFORMER OIL SAMPLES --General	$ 300.57	✓

Table 6: Unit cost of various Preventative Maintenance Activities. Based on actual unit cost from 2013-2015

7.2 Net Present Value Analysis

This session evaluates the cost benefit for various asset management options (Status Quo Maintain, repair, replacement) of T11 with Net Present Value Analysis (NPV), where:

- Status Quo Maintain: Perform routine maintenance to keep the unit in service. Replace at economic end of life (2027). Continue to maintain to end of study period (2067).
- Repair/Refurbish: Perform major repair/refurbishment in the year of interest (2017), then maintain as normal and replace the unit at economic end of life (2027). Continue to maintain to end of study period (2067).
- Replace: Advance the replacement to the year of interest (2017) instead of performing a refurbishment. Continue to maintain to end of study period (2067).

The study makes the following assumptions:

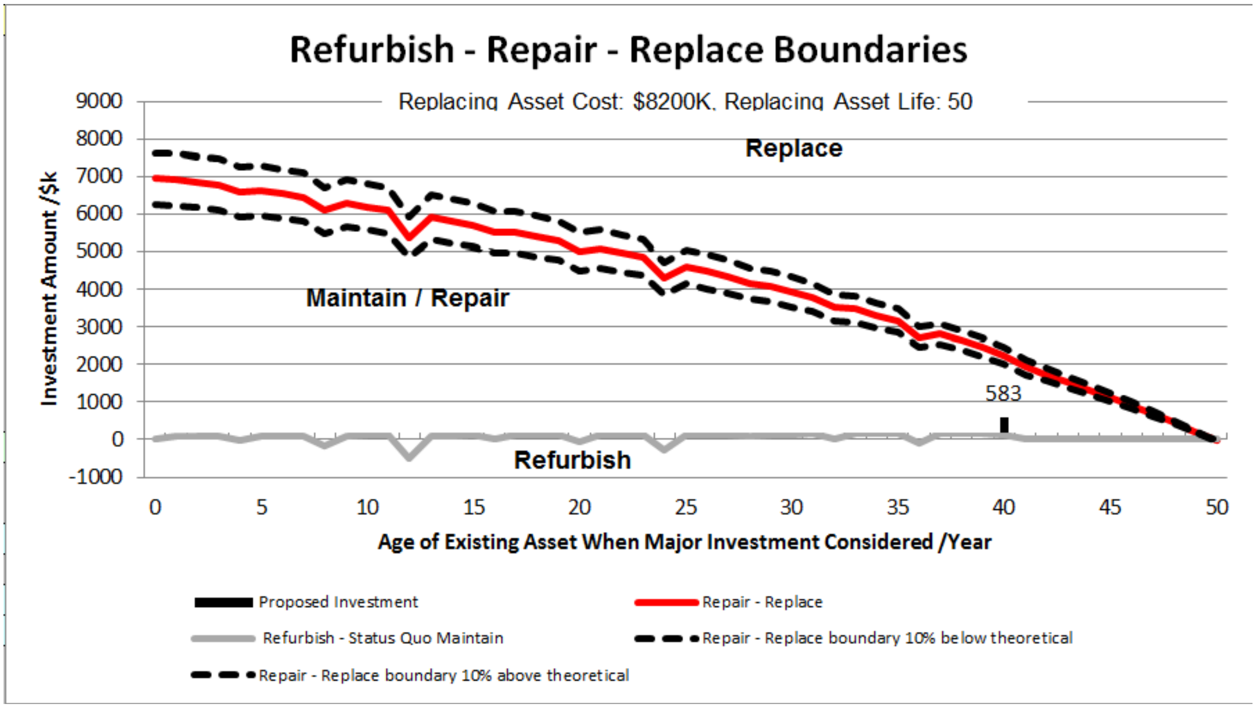
- Study period : 50 years
- T11 will undergo refurbishment/ repair at 40 year old (2017), at approx. CAD$583.8k[1].
- Replacement cost is assumed to be CAD$8.2M[2] for a unit that matches purchasing standard S230-102
- The new unit will benefit from lower OM&A cost because it will be equipped with vacuum tap changer. Estimated interval for internal inspection is lengthen to 12 years. New unit will utilize Buchholz relay and eliminate D2 maintenance task.
- Inflation: 2%. [2]
- Cost of Capital: 5.78% [2]
- Corporate Tax rate : 26.5% [2]
- CCA rate for Transmission Asset : 8% [2]
- Disposal Value : $0
- Average corrective unit cost per year for T11 is CAD$18,879.91. (CAD $188,799.09 total till the end of study period).

NPV of 3 options (Status Quo Maintain, Repair and Replace) were evaluated under the aforementioned assumptions. In general, NPV calculation has preferred the option to maintain status quo and wait for replacement as it has the lowest present value. The PV difference is significant between refurbishment and replacement option is (CAD $583.8K + CAD $1652.76 K = CAD $2235.76K). Therefore, the model suggests that it will be more economical to repair/refurbish the unit in 2017.

Result Summary	Status Quo Maintain	Major Investment Maintain/Repair	Replace	Preferred Option
With CCA tax savings				
PV of Options, $k, with terminal value	5092.13	5411.48	7064.24	
PV of Options, $k, terminal value = 0	5212.54	5531.89	7064.24	
Investment Decision		NPV, $k		
Status Quo Maintain - Refurbish		-319.35		Maintain
Major Investment (Repair/Refurbish) - Replace		-1652.76		Repair/Refurbish
Repair - Replace boundary			2235.76	
Repair - Replace boundary, upper bound			2459.33	
Repair - Replace boundary, lower bound			2012.18	

Table 7: Present Value comparison for different sustainment options

[1] $583.8 K is the 2010 – 2015 recorded average cost to refurbish transformer under AR 18335 (Transformer Oil Leak Reduction)
[2] Based on 2015 March, Average I/S Cost for Autotransformers in 230kV class.



Graph 6: Visual Representation of NPV analysis

8 Conclusion

The demographics data, condition data, environmental/HSE hazards, equipment loading and economics related to Marathon T11 have been reviewed. T11's oil is in good condition and shows little insulation deterioration. T11's overall maintenance history reported major upgrades in the past with acceptable corrective costs. While T11's has recorded higher than expectation OM&A expenses, majority of these costs are related to upgrade activities that are non-repetitive. A review of T11's loading has revealed that it is lightly loaded with respect to its various loading limits from 2011-2015. An NPV analysis has been performed and has concluded that it is more economical to operate the unit as is and perform refurbishment/repair in 2017 if required. In conclusion, given the unit is in decent condition, it is suggested to continue normal operation and monitoring for T11 for the next 5 years. A re-assessment 5 years from 2016 is considered prudent.

9 Reference

[1] Conestoga-Rogers & Associates. (2011). Hydro One Station Spill Risk Model. SIP-EnvMgmt-0100, Mississauga.

[2] Department of Economics and Load Forecasting, Hydro One Networks Inc. (2015), Hydro One Financial Evaluation Model, Toronto.

APPENDIX 1 – PREVENTIVE MAINTENANCE RESULT

Notification	Notifictn type	Notif.date	Coding	Functional Loc.	Description
10004239	PR	05/31/2008		N-TS-MARATHONTS-TF-T11	TF-GENERAL-DBT
10023296	PR	07/04/2008	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
10023404	PR	07/04/2008		N-TS-MARATHONTS-TF-T11	TF-GENERAL-D1
10023403	PR	07/04/2008		N-TS-MARATHONTS-TF-T11	TF-GENERAL-M1
10029541	PR	07/16/2008	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-DBT
10130775	PR	10/02/2008	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10130815	PR	10/02/2008	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10184737	PR	10/23/2008		N-TS-MARATHONTS-TF-T11	TF-GENERAL-M1
10239112	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239128	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239129	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239130	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239131	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239132	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239133	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239134	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239135	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239136	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239167	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10239168	PR	12/22/2008	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10268645	PR	03/02/2009		N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-M1
10268646	PR	03/02/2009		N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-M1
10272272	PR	03/13/2009		N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-M1
10278247	PR	03/24/2009	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10388242	PR	11/05/2009	CR03	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI
10408678	PR	12/09/2009		N-TS-MARATHONTS-TF-T11	TF-GENERAL-M1
10430569	PR	01/06/2010	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10432529	PR	01/08/2010	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
10480590	PR	03/25/2010	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING

10480661	PR	03/25/2010	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING
10480662	PR	03/25/2010	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING
10480663	PR	03/25/2010	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING
10497254	PR	04/29/2010	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10497320	PR	04/29/2010	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10561990	PR	10/04/2010	CR02	N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
10561504	PR	10/04/2010	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10561247	PR	10/04/2010	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10561505	PR	10/04/2010	CR01	N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-UTOA
10593609	PR	10/15/2010	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-D1
10592366	PR	10/15/2010		N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-M1
10592836	PR	10/15/2010		N-TS-MARATHONTS-TF-T11	UT-MR/EFM-1/3-800A-M1
10638170	PR	12/28/2010	CR03	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL
10638194	PR	12/28/2010	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL
10638195	PR	12/28/2010	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL
10638196	PR	12/28/2010	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL
10687382	PR	05/06/2011		N-TS-MARATHONTS-TF-T11	20216 2011 TX PCB Reduction Oil Sample
10752232	PR	10/05/2011	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
10752233	PR	10/05/2011	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
10752234	PR	10/05/2011	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
10752235	PR	10/05/2011	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
10802243	PR	11/24/2011	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2011
10802287	PR	11/24/2011	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2011
10802288	PR	11/24/2011	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2011
10802289	PR	11/24/2011	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2011
11827704	PR	10/13/2012	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
11825930	PR	10/13/2012	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
11825374	PR	10/13/2012	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
11825931	PR	10/13/2012	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
12647980	PR	09/26/2013	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
12645235	PR	09/26/2013	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA

12644341	PR	09/26/2013	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
12645237	PR	09/26/2013	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
12802625	PR	11/25/2013	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPR 2013
12802700	PR	11/25/2013	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPR 2013
12802701	PR	11/25/2013	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPR 2013
12802702	PR	11/25/2013	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPR 2013
12887098	PR	03/22/2014	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
13001676	PR	05/26/2014	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2014
13001699	PR	05/26/2014	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2014
13001700	PR	05/26/2014	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2014
13001701	PR	05/26/2014	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2014
13371517	PR	09/26/2014	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
13369956	PR	09/26/2014	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
13369721	PR	09/26/2014	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-SI
13369457	PR	09/26/2014	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
13369958	PR	09/26/2014	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
13380780	PR	09/27/2014	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-DBT
13384558	PR	09/27/2014	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-D2
13380769	PR	09/27/2014	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-D1
13379082	PR	09/27/2014	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-SI
13379083	PR	09/27/2014	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-SI
13519455	PR	01/30/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2014
13519546	PR	01/30/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2014
13519547	PR	01/30/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2014
13519548	PR	01/30/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2014
13749501	PR	05/14/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2015
13749533	PR	05/14/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2015
13749534	PR	05/14/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2015
13749536	PR	05/14/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2015
14043404	PR	07/24/2015	CR01	N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
14042421	PR	07/24/2015	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA

14042164	PR	07/24/2015	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
14042422	PR	07/24/2015	CR01	N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
14313541	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313461	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313462	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313463	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313464	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313465	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313466	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313467	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313468	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313469	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14313540	PR	10/21/2015	CR01	N-TS-MARATHONTS-TF-T11	Tx PCB Reduction Oil Sample
14403857	PR	11/19/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2015
14403885	PR	11/19/2015	CR03	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2015
14403871	PR	11/19/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2015
14403872	PR	11/19/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2015
14403873	PR	11/19/2015	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2015
14658654	PR	05/12/2016	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2016
14658509	PR	05/12/2016	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2016
14658530	PR	05/12/2016	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2016
14658531	PR	05/12/2016	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI SPRING 2016
14916069	PR	07/16/2016		N-TS-MARATHONTS-TF-T11	TF-GENERAL-GOT
14912109	PR	07/16/2016		N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
14907349	PR	07/16/2016		N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
14912140	PR	07/16/2016		N-TS-MARATHONTS-TF-T11	UT-MR-MI-UTOA
15246621	PR	11/14/2016	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2016
15246678	PR	11/14/2016	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2016
15247042	PR	11/14/2016	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2016
15246690	PR	11/14/2016	CR01	N-TS-MARATHONTS-TF-T11	STN 'B' PWR EQ INSP-SVI FALL 2016

APPENDIX 2 – LIST OF DR AND TC NOTIFICATION

Notification	Notifictn type	Notif.date	Coding	Functional Loc.	Description
10398924	DR	11/19/2009	3810	N-TS-MARATHONTS-TF-T11	T11 Tapch indic board failed
10461008	DR	02/02/2010		N-TS-MARATHONTS-TF-T11	Marathon T11 grounding stirrup
10524669	TC	07/07/2010		N-TS-MARATHONTS-TF-T11	sect 3 re marathon
11643335	DR	08/28/2012		N-TS-MARATHONTS-TF-T11	Marathon TS T11 Oil Leak
11696160	DR	09/10/2012		N-TS-MARATHONTS-TF-T11	T11/T12 tapch filter acad controls
12471463	DR	08/02/2013		N-TS-MARATHONTS-TF-T11	MARATHON TS 15T11 OIL LEAK
12716240	DR	10/17/2013		N-TS-MARATHONTS-TF-T11	Marathon TS T11 Differential Investigate
12868356	DR	02/13/2014	4200	N-TS-MARATHONTS-TF-T11	P15 Inspect transfrmer for oil leaks
13040667	DR	06/12/2014	9900	N-TS-MARATHONTS-TF-T11	T11 bushing reported smoking/over heatin
13038920	DR	06/12/2014	9800	N-TS-MARATHONTS-TF-T11	T11 - replace tertiary bushings
13460667	TC	11/27/2014		N-TS-MARATHONTS-TF-T11	S4: EMD RE: T11 BREATHER FAIL AT MARATHO
13468578	TC	12/09/2014		N-TS-MARATHONTS-TF-T11	S4 T11 BREATHER FAIL
13532253	DR	02/17/2015		N-TS-MARATHONTS-TF-T11	Replace heating element on conserv breat
13533644	TC	02/19/2015		N-TS-MARATHONTS-TF-T11	S4 EMD PD T11 BREATHER FAIL ALARM MARATH
14378032	DR	11/11/2015		N-TS-MARATHONTS-TF-T11	T11 slow leak on top near tapchanger
14412048	DR	11/23/2015		N-TS-MARATHONTS-TF-T11	Marathon T11pipe leaking/need cms welder
14489339	TC	01/04/2016		N-TS-MARATHONTS-TF-T11	S4 - PENDING EMD MARATHON TS T11 BREATHE
15070279	TC	09/07/2016		N-TS-MARATHONTS-TF-T11	S4-EMD-PND RE: T11 TAP CHANGER TROUBLE

APPENDIX 3 – OIL LEAKS OBSERVATIONS

Oil leaks at CT junction boxes

OEB INTERROGATORY #78

Reference:

TSP-01-04-13

Interrogatory:

Throughout its report, METSCO provides recommendations to Hydro One for improving its asset management practices.

a) In a tabular format listing all the recommendations and suggestions provided by METSCO, please specify if and how Hydro One will implement the recommendations, and the timeframes within which the recommendations will be implemented.

Response:

Please see the response on the next page.

Rec Num	METSCO Recommendation	Hydro One Decision	Timeline
1	Consider clearly separating the risk factors/criteria in AA to (a) define probability of failure of a specific asset, and (b) incorporate the impact of asset failure to explicitly assess a broader variety of outage consequence costs, such as utility's and socioeconomic costs, including the costs associated with the environment, safety/collateral damages, environment, customer interruption costs and financial impacts. Given that many of these additional factors proposed for incorporation into AA are already considered in the subsequent ARA analysis, we qualify this recommendation by stating that HONI may wish to consider it at a juncture where a broader AM process reorganization may be contemplated.	As noted in the recommendation, this is current applied through the ARA process. Therefore this would be duplicative and the cost to implement exceeds the benefit of incorporating into AA. The ARA process already considers many of the broader consequences outlined. No further action will be taken at this time.	No further action
2	Re-visit the formulation of its present AA framework and consider potential regrouping / renaming of assessment factors components to better align it with commonly understood industry terminology (such as condition assessment/health index, or impact assessment/consequence cost), and take steps to develop more comprehensive explanatory manuals for its AA capabilities.	Explanatory manuals have been developed for the AA capabilities. Updating to broader use terminology will be done opportunistically if and when the existing explanatory manuals are revisited.	N/A

Rec Num	METSCO Recommendation	Hydro One Decision	Timeline
3	Continue ongoing work to rectify data completeness gaps identified across the individual risk sub-categories for each asset class in section 3.2, aiming for the highest practicable scores within the resource availabilities, and prioritizing the categories seen as most impactful in light of the criteria weightings.	Critical data completeness is sufficiently acceptable to provide information on the assets to be able to make effective decisions. Having said that, there is an ongoing effort to continually rectify any data gaps that are identified which are not material to decision making.	Ongoing
4	Consider supplementing the current condition parameters tracked for each major asset class with additional parameters tracked in the industry, as identified in the appropriate subsections of section 3.2. As with all input enhancements, evaluate the incremental value proposition of additional parameters relative to the implementation costs by way of financial value for money analysis.	Hydro One is currently working towards enhancements of the condition parameters.	No later than 2024

Rec Num	METSCO Recommendation	Hydro One Decision	Timeline
5	Consider integration socio-economic factors, including costs to the customer (customer interruption costs), as well as environmental and safety-related monetary cost factors, such that the full range of economic costs (including those that go beyond those incurred by a utility or its customers) can be utilized as part of this evaluation procedure.	Hydro One does not view this recommendation as material to the AA and ARA process as the ARA is tailored to determine specific asset needs and identify customer needs and preferences. Prioritization of investments is established through the Investment Planning Process as defined in TSP Section 2.1. Safety, environment and reliability risk, are already considered for each candidate investment.	No further action
6	Consider supplementing the obsolescence-based intervention assessments for Protection, Control, and Telecom assets by formally incorporating the results of manual SME activities that already occur in a less formalized manner.	AA will work with Protection, Control and Telecom subject matter experts (SME) to determine the feasibility of incorporating the results of manual SME activities. The ARA process already considers obsolescence-based intervention as part of the overall process.	End of 2019

Rec Num	METSCO Recommendation	Hydro One Decision	Timeline
7	Prior to investing any incremental resources into potential refinements, we encourage Hydro One's management to fully articulate a vision of the tool's ultimate place within its asset management and capital planning hierarchy, including whether such a tool is ultimately needed in light of all other capabilities. Subject to the outcome of deliberations suggested in the above recommendation, consider further enhancements to reliability forecasting through an RRM, or an alternative solution.	Please refer to Exhibit B-1-1 TSP Section 1.3 Attachment 4: Hydro One is aware of reliability forecasting models however comprehensive assessment and testing of these models are not complete. Hydro One has completed substantial work in developing and refining hazard functions of its assets as discussed in TSP Section 1.4 which form a good baseline for forecasting investment requirements. Hydro One will continue to explore and assess other reliability forecasting models to quantify the outcome of its investment plan in the future.	Closed
8	Enhance reliability forecasting to assess reliability performance of the transmission system through a variety of reliability indices, rather than rely on the reliability risk modeling.	See Recommendation 7.	See Recommendation 7.

Rec Num	METSCO Recommendation	Hydro One Decision	Timeline
9	Integrate the enhanced reliability forecasting solution into the overall asset management process to provide the asset managers with a more robust set of reliability outcome predictions based on a variety of investment scenarios under consideration.	See Recommendation 7.	See Recommendation 7.
10	Include additional asset classes into the reliability forecasting approach (e.g. tower structures, insulators, switches) and sub-classes to improve the precision level of equipment related risk forecasting.	See Recommendation 7.	See Recommendation 7.
11	Develop a capability to provide reliability risk prediction on a sub-system level, such as system regions or large customer groups.	See Recommendation 7.	See Recommendation 7.
12	Expand the overall approach to reliability / reliability risk forecasting to factor in non-equipment related outages (e.g. weather events, adverse environment, human related errors, foreign interference, etc.) to forecast the reliability risks of the transmission system as a whole.	See Recommendation 7.	See Recommendation 7.

Rec Num	METSCO Recommendation	Hydro One Decision	Timeline
13	Assess the reliability impact of the non-renewal projects in the enhanced reliability forecasting solution. If the utility does not have any such projects in the investment plan, than the benefits of this recommendation are not expected to outweigh the costs of developing this capability.	See Recommendation 7.	See Recommendation 7.
14	Extend the reliability forecasting horizon to at least ten years to capture a greater extent of the long-lasting renewal and non-renewal projects within the investment scenarios on the system reliability.	See Recommendation 7.	See Recommendation 7.
15	Enhance the algorithms utilized to calculate the age demographic profile for each asset class, by revisiting the priority of asset replacements and considering both reactive and inspection-determined failure modes of assets reaching their ends of lives.	See Recommendation 7.	See Recommendation 7.
16	Revise asset class weights or the algorithms that calculate the reliability risk of three key asset classes per each investment scenario to incorporate more asset-specific failure considerations.	See Recommendation 7.	See Recommendation 7.

Witness: Donna Jablonsky

Rec Num	METSCO Recommendation	Hydro One Decision	Timeline
17	Utilize a variety of econometric techniques to establish mathematical relationships between the non-asset and asset-related failure instances or modes, and factors that precipitate them.	See Recommendation 7.	See Recommendation 7.

OEB INTERROGATORY #79

Reference:

TSP-01-04-13 p. 76-78

Interrogatory:

At the above noted reference, METSCO provided overall recommendations and risk results for ABC TS (Figure 27)

a) Please provide the original Hydro One Risk Assessment that informed the results shown in Figure 27 of the METSCO report.

Response:

a) Figure 27 presents Hydro One's recommendations and risk results. The station assessment may be found at Attachment 1.

Bridgman TS
T11, T12, T13

Station Assessment

[Keyword]

Information Type: Intellectual Property - Refer to Policy SP1139

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REVISION HISTORY

Date	Revision	Revision Comments
July 10, 2015	0	First Draft

TABLE OF CONTENTS

1.0 INTRODUCTION

This assessment provides an overview of the current state of the station. The recommendations offered in this document will allow Asset Management make well-informed capital investment decisions.

Integration of the replacement of multiple end of life components into a single investment allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work. A station assessment will ensure that all the replacement needs are captured and integrated into the investment before release.

2.0 STATION SUMMARY

The Bridgman TS supplied by three L13W, L14W, and L15W 115kV power lines. Station has five step-down power transformers: T11, T12, T13, T14, T15. **Three** double secondary power transformers with the following rating: 40/66MVA, 115kV-14.2kV-14.2kV, Y/D/D - T11, T12, T13, **one** double secondary power transformer 45/75MVA, 115kV-14.2kV-14.2kV, D/Y/Y - T14, and **one** double secondary power transformers 60/80/100MVA, 115kV-14.2kV-14.2kV, D/Y/Y - T15 which is scheduled to be in service spring 2015. Power transformers supply THES substation. Station located in Toronto area.

3.0 DESKSIDE STATION ASSESSMENT

3.1 Station Fault Current Rating

Table 1: 2014 Station Fault Current Rating for Bridgman TS [1].

Bridgman TS	Symmetrical		Asymmetrical		Symmetrical Rating		Asymmetrical Rating	
	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA	3ph kA	LG kA
A1A2SS1 Bus@ 13.8 kV	17.371	9.929	18.814	12.099	19.01	19.01	20.91	20.91
HIGHLE12 Bus@ 13.8 kV	15.535	0.741	17.8	0.904	17.50	17.50	19.30	19.30
HIGHLE56 Bus@ 13.8 kV	17.206	0.753	20.07	0.919	25.00	25.00	27.50	27.50
HIGHLE78 Bus@ 13.8 kV	17.603	0.753	19.16	0.918	17.50	17.50	19.30	19.30

3.2 Station 5 Year DESN Loading (2010-2014)

Table 2: Transformer MVA Ratings, 5-Yr Avg, 5-Yr Peaks & Loading Deviation %'s

DESN	TF Max Rating (MVA)	StDev % of Max Avg	Max Avg (MVA) 2008-12	Max Avg % of TF Max Rtg	Max Peak vs Max Avg	StDev % of Max Peak	Max Peak (MVA) 2008-12	Max Peak % of TF Max Rtg	Max Peak MVA as % of LTR Avg	LTR Load Risk	LTR vs TF Max Rtg
T11/T12/T13 T14/T5/T6	169.8 (sum of 3TF's)	40.6%	120.22	70.8%	196.5%	50.6%	236.24	139.1%	90.0%	Y	1.5

Table 3: Station LTR Ratings and Average Peak Loading for transformers

	LTR Rating		2010		2011		2012		2013		2014	
DESN	**Sum 10d LTR**	**Win 10d LTR**	**Avg [MVA]**	**Peak [MVA]**	**Avg [MVA]**	**Peak [MVA]**	**Avg [MVA]**	**Peak [MVA]**	**Avg [MVA]**	**Peak [MVA]**	**Avg [MVA]**	**Peak [MVA]**
T11-X HLA5/HLA6	40.9	45.95	7.57	26.93	8.03	17.29	7.36	13.88	6.64	23.22	7.73	19
T5 HLA5/HLA6	52.8	44.88	11.32	22.92	12.02	16.08	10.79	19.27	13.73	35.82	15.68	28.86
T11-Y HLA1/HLA2	40.9	45.95	9.87	26.11	10.88	16.92	15.41	21.89	10.42	20.95	12.16	22.85
T13-X HLA1/HLA2	39.5	43.9	14.73	25.01	14.27	18.91	10.35	17.53	15.17	26.04	16.51	23.46
T14-X HLA1/HLA2	40.9	45.25	9.89	32.2	9.39	14.6	14.56	25.13	11.57	31.25	13.94	26.37
T6 HLA7/HLA8	52.8	44.88	14.82	34.07	14.96	19.41	19.38	40.59	17.05	38.63	17.42	35.16
T12-X HLA7/HLA8	39.9	44.45	10.43	25.41	10.52	16.88	14.63	20.93	9.45	17.22	8.36	18.18
T13-Y HLA7/HLA8	39.5	43.9	12.91	27.3	12.73	16.54	9.21	15.19	13.25	30.47	12.97	17.94
T12-Y A1/A2	39.9	44.45	14.5	30.25	16.29	23.49	16.57	20.72	14.08	36.35	15.4	22.23

T14-Y A1/A2	40.9	45.25	13.6	38.01	15.08	21.05	12.85	24.36	14.66	22.83	16.15	25.86

Table 3: Station LTR Ratings and Average Peak Loading for M/C.

	LTR Rating		2010		2011		2012		2013		2014	
DESN	Sum 10d LTR	Win 10d LTR	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]	Avg [MVA]	Peak [MVA]
T11-X HLA5/HLA6	40.9	45.95	18.89	35.57	20.05	32.21	17.2	36.75	18.5	53.87	17.57	41.39
T5 HLA5/HLA6	52.8	44.88										
T11-Y HLA1/HLA2	40.9	45.95	34.49	56.1	34.54	43.97	35.41	55.74	25.38	63.68	40.74	67.01
T13-X HLA1/HLA2	39.5	43.9										
T14-X HLA1/HLA2	40.9	45.25										
T6 HLA7/HLA8	52.8	44.88	38.16	62.6	38.21	48.37	37.8	56.12	37.49	72.8	36.85	59.81
T12-X	39.9	44.45										

HLA7/HLA8												
T13-Y HLA7/HLA8	39.5	43.9										
T12-Y A1/A2	39.9	44.45	28.1	51.85	31.37	42.53	27.9	46.25	28.01	36.35	28.91	41.81
T14-Y A1/A2	40.9	45.25										

3.2.1 Stranded Load [2]

Station	Breakers	Connections	Stranded
Bridgman TS			Yes 100%

3.3 Customer Information

Table 4: Customer Satisfaction Summary

Customer Name	Customer Satisfaction Rating					Trend
	2009	2010	2011	2012	2013	
Toronto Hydro Electric System Limited	Not Surveyed	Not Surveyed	Not Disclosed	Neither Satisfied nor dissatisfied	Somewhat Satisfied	Improving

3.4 Outage Information

The Bridgman TS T11/T12/T13/T14/T5/T6 yard is not considered a Delivery Point (DP) group or individual outlier (Frequency or Duration). The 10 year average performance is very good.

Frequency>>>

10 yr avg	3 yr average

OPDES	Bus MW	DESN MW	13-04	13-11	12-10	11-09	10-08	09-07	08-06	07-05	06-04	Indiv. Outlier Baseline (Freq)	Group Outlier Freq Target	Group Outlier Freq UB
A1A2		95.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.3	1.0
HLA1A2		95.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.0
HLA7A8		95.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.3	1.0
HLA5		95.8	0.1	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.3	1.0
HLA6		95.8	0.1	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.3	1.0

Duration>>>

			10 yr avg	3 yr average										
OPDES	Bus MW	DESN MW	13-04	13-11	12-10	11-09	10-08	09-07	08-06	07-05	06-04	Indiv. Outlier Baseline (Dur.)	Group Outlier Dur. Target	Group Outlier Dur. UB
A1A2		95.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	5.0	25.0
HLA1A2		95.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	25.0
HLA7A8		95.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.4	5.0	25.0
HLA5		95.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.8	5.0	25.0
HLA6		95.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	25.0

3.5 Station Spill Risk Ranking

Bridgman TS has 6 oil-filled power transformers supplying THES substations. The overall station is ranked 4th out of 256 stations based on existing risk score from a 2011 spill risk report by Conestoga-Rogers & Associates and considered at Moderate Risk [3].

3.6 Asset Analytics

Based off the Composite score in Asset Analytics, the following station equipment, not previously identified under the asset-centric work program, with a *Composite* score greater than 35 or a *Demographic* score greater than 74 should be considered for replacement.

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BRIDGMANTS-PR-T11YH BF	Protection: Electro Mechanical	49	1	100	45	55	0	10	36
N-TS-BRIDGMANTS	TS	62	34	84	18	32	38	1	36
N-TS-BRIDGMANTS-SW-T11-L13W	Switch: Air Break_115 kV	59	45	100	40	1	100	33	45
N-TS-BRIDGMANTS-TF-T11	Transformer: Step-down_115 kV	56	27	100	28	30	38	21	37
N-TS-BRIDGMANTS-TF-T14	Transformer: Step-down_115 kV	42	60	100	16	41	39	21	50
N-TS-BRIDGMANTS-TF-T5	Transformer: Step-down_115 kV	63	65	100	30	35	37	21	51
N-TS-BRIDGMANTS-TF-T12	Transformer: Step-down_115 kV	58	70	100	6	45	38	21	53
N-TS-BRIDGMANTS-TF-T6	Transformer: Step-down_115 kV	60	20	100	42	50	37	21	41
N-TS-BRIDGMANTS-TF-T13	Transformer: Step-down_115 kV	58	27	100	18	51	38	21	42
N-TS-BRIDGMANTS-PR-T6 MAIN	Protection: Electro Mechanical	55	1	100	22	80	0	1	40
N-TS-BRIDGMANTS-TC- T1MX0101M	Telecom: MUX Interfaces	8	33	1	100	100	0	1	54
N-TS-BRIDGMANTS-SW-T12-L13W	Switch: Air Break_115 kV	56	45	100	40	1	100	33	45
N-TS-BRIDGMANTS-SW-T13-L15W	Switch: Air Break_115 kV	56	45	100	40	1	100	33	45
N-TS-BRIDGMANTS-SW-T5-L14W	Switch: Air Break_115 kV	57	45	100	40	1	100	33	45
N-TS-BRIDGMANTS-SW-T6-L14W	Switch: Air Break_115 kV	57	45	100	40	1	100	33	45

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite
N-TS-BRIDGMANTS-PR-T11 X MAIN	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T11 Y BU	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T11 Y MAIN	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T11YH BF	Protection: Electro Mechanical	49	1	100	45	55	0	10	36
N-TS-BRIDGMANTS-PR-T12 X BU	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T12 X MAIN	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS	TS	62	34	84	18	32	38	1	36
N-TS-BRIDGMANTS-SW-T11-L13W	Switch: Air Break_115 kV	59	45	100	40	1	100	33	45
N-TS-BRIDGMANTS-PR-T12XH BF	Protection: Electro Mechanical	49	1	100	1	1	0	10	14
N-TS-BRIDGMANTS-PR-T12YB BF	Protection: Solid State	49	1	100	1	1	0	10	14
N-TS-BRIDGMANTS-PR-T13 X BU	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T13 X MAIN	Protection: Electro Mechanical	54	1	100	59	42	0	1	32
N-TS-BRIDGMANTS-PR-T14YB BF	Protection: Solid State	49	1	100	1	1	0	10	14
N-TS-BRIDGMANTS-PR-T5 BU	Protection: Electro Mechanical	55	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T5 MAIN	Protection: Electro Mechanical	55	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T5 X MAIN	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-IT-T11PT1	IT: Potential Transformer	59	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-IT-T14PT2	IT: Potential Transformer	39	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-IT-T13PT2	IT: Potential Transformer	34	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-IT-T5PT	IT: Potential Transformer	55	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-TF-T11	Transformer: Step-down_115 kV	56	27	100	28	30	38	21	37
N-TS-BRIDGMANTS-IT-T11PT2	IT: Potential Transformer	59	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-IT-T13PT1	IT: Potential Transformer	34	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-PR-T13 Y MAIN	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T13XH BF	Protection: Electro Mechanical	49	1	100	1	1	0	10	14
N-TS-BRIDGMANTS-PR-T14 B	Protection: Solid State	33	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-IT-T12PT2	IT: Potential Transformer	57	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-TF-T14	Transformer: Step-down_115 kV	42	60	100	16	41	39	21	50
N-TS-BRIDGMANTS-TF-T5	Transformer: Step-down_115 kV	63	65	100	30	35	37	21	51
N-TS-BRIDGMANTS-IT-T14PT1	IT: Potential Transformer	34	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-IT-T6PT	IT: Potential Transformer	56	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-TF-SS2	Transformer: Station Service_< 69 kV	61	1	100	25	1	1	26	16
N-TS-BRIDGMANTS-IT-T12PT1	IT: Potential Transformer	57	1	100	1	1	0	22	15
N-TS-BRIDGMANTS-TF-T12	Transformer: Step-down_115 kV	58	70	100	6	45	38	21	53
N-TS-BRIDGMANTS-TF-T6	Transformer: Step-down_115 kV	60	20	100	42	50	37	21	41
N-TS-BRIDGMANTS-TF-T13	Transformer: Step-down_115 kV	58	27	100	18	51	38	21	42
N-TS-BRIDGMANTS-BR-A1A2SS1	Breaker: Air Blast_< 69 kV	57	17	100	1	1	30	21	22
N-TS-BRIDGMANTS-BR-T12YB	Breaker: Metal Clad Air Blast_< 69 kV	57	17	100	1	1	100	29	32
N-TS-BRIDGMANTS-BR-T14YB	Breaker: Metal Clad Air Blast_< 69 kV	57	17	100	5	1	91	29	31
N-TS-BRIDGMANTS-PR-T6 BU	Protection: Electro Mechanical	55	1	100	19	1	0	1	15
N-TS-BRIDGMANTS-PR-T6 MAIN	Protection: Electro Mechanical	55	1	100	22	80	0	1	40
N-TS-BRIDGMANTS-PR-T6 X MAIN	Protection: Electro Mechanical	54	1	100	1	1	0	1	14
N-TS-BRIDGMANTS-PR-T6H BF	Protection: Electro Mechanical	49	0	100	1	1	0	10	22
N-TS-BRIDGMANTS-SW-T12-L13W	Switch: Air Break_115 kV	56	45	100	40	1	100	33	45
N-TS-BRIDGMANTS-SW-T13-L15W	Switch: Air Break_115 kV	56	45	100	40	1	100	33	45
N-TS-BRIDGMANTS-SW-T5-L14W	Switch: Air Break_115 kV	57	45	100	40	1	100	33	45
N-TS-BRIDGMANTS-SW-T6-L14W	Switch: Air Break_115 kV	57	45	100	40	1	100	33	45

3.7 The High Level MTS

Func. Location	Asset T	Asset Class	Volta	ge	ndition	mographics	onomics	rformance	ilization	ticality	mposite
N-TS-THIGHLEVMT	Station	SS	0	33	16	100	1	20	2	1	24
N-TS-THIGHLEVMT-BR-T13YH	Breaker	Breaker: Metal Clad SF6_< 69 kV	13.8	25	13	100	1	1	4	29	18
N-TS-THIGHLEVMT-BR-T14XH	Breaker	Breaker: Air Blast_< 69 kV	13.8	54	17	100	1	1	1	29	19
N-TS-THIGHLEVMT-BR-T6H	Breaker	Breaker: Air Blast_< 69 kV	13.8	54	17	100	1	1	1	29	19
N-TS-THIGHLEVMT-BR-T11YH	Breaker	Breaker: Air Blast_< 69 kV	13.8	54	17	100	1	60	1	29	35
N-TS-THIGHLEVMT-BR-T12XH	Breaker	Breaker: Air Blast_< 69 kV	13.8	54	17	100	1	1	1	29	19
N-TS-THIGHLEVMT-BR-T13XH	Breaker	Breaker: Air Blast_< 69 kV	13.8	54	17	100	1	60	1	29	35
N-TS-THIGHLEVMT-BR-T11A6	Breaker	Breaker: Metal Clad SF6_< 69 kV	13.8	22	13	100	1	1	5	29	18
N-TS-THIGHLEVMT-BR-T11A5	Breaker	Breaker: Metal Clad SF6_< 69 kV	13.8	22	13	100	1	1	5	29	18

3.8 Station Security

Bridgman TS is classified as Medium Risk and as of July 2014 has experienced three (3) break-ins since 2007. The history of break-ins at Bridgman TS is shown in Table 1.

Table 1: Count of Break-Ins by Year at Bridgman TS

2007	2008	2009	2010	2011	2012	2013	2014
0	0	0	0	0	0	0	3

As per ***SP-14-001-R1:*** *Functional Requirements for Preventing Copper Theft*, and ***SP-14000-001-R0:*** *Functional Requirements for Transmission and Distribution Security Detection and Verification Systems*, all stolen/missing *below grade* fence grounding and power equipment grounding conductors are to be replaced with copper-clad steel conductors whenever safely possible and when the original copper conductor was 4/0# or smaller. In addition, all stolen/missing *above grade* fence grounding is to be replaced with aluminum grounding material.

Defined as a Medium Risk station, current functional requirements dictate that the station be enclosed by a standard 8' (2.44 m) chain link perimeter fence.

For reference, criteria for station security risk classification are summarized in Table 2, below.

Table 2: Security Risk Classifications

Security Risk Level	Description
High	10+ break-ins from 2007- present
Medium	1-9 break-ins from 2007- present
Low	0 break-ins from 2007- present

3.9 Potential Need & Deficiency Report Notifications

Below is a summary of Potential Needs (PN) and Deficiency Report (DR) notification that have been issued by Field Staff and currently outstanding.

Table 3: Listing of Open and Outstanding Potential Needs (PN) Notifications

Notification	Functional Loc.	Notif.date	Description
13420045	N-TS-BRIDGMANTS-SI-BLDG D	10/27/2014	Bridgman cable tunnel - corrosion
10501739	N-TS-BRIDGMANTS-BR	05/07/2010	BRIDGMAN BREAKER TCM
10501738	N-TS-BRIDGMANTS-PR-T11YH BF	05/07/2010	BRIDGMAN T11YH BREAKER TCM
10339903	N-TS-BRIDGMANTS-TF-T14	07/28/2009	T14

Table 4: Listing of Open and Outstanding Deficiency Report Notifications for the LV yard

Notification	Functional Loc.	Notif.date	Description
13554852	N-TS-BRIDGMANTS-PR	03/13/2015	AL0368 NT31 Potential Defect DC Mont Cab
13606607	N-TS-BRIDGMANTS-TF-T12	04/10/2015	Bridgman TS T12 All Cooling Fans
13561546	N-TS-BRIDGMANTS-TF-T11	03/20/2015	Oil barrel at Bridgman TS T11 March
13547260	N-TS-BRIDGMANTS-TF-T6	03/04/2015	Bridgman T6 investigation
12686439	N-TS-BRIDGMANTS-SI-BLDG A	10/03/2013	BLDG-Repair&paint ceilings&walls
13507337	N-TS-BRIDGMANTS-BR	01/21/2015	Bridgman/High Level Non Arc Proof Labels
13430495	N-TS-BRIDGMANTS-TF-T11	11/07/2014	Bridgman TS T11 Low Oil Level
13430492	N-TS-BRIDGMANTS-TF-T11	11/07/2014	Bridgman TS T5 Low Oil Level
13430493	N-TS-BRIDGMANTS-TF-T5	11/07/2014	Bridgman TS T5 Oil leak
13430494	N-TS-BRIDGMANTS-TF-T6	11/07/2014	Bridgman TS T6 One cooling fan
12941470	N-TS-BRIDGMANTS-TF-T6	04/30/2014	One cooling fan not working.
12770553	N-TS-BRIDGMANTS-TF-T5	11/13/2013	Bridgman TS T5 Low Oil Level
12786508	N-TS-BRIDGMANTS-TF-T13	11/19/2013	T13 Y winding temp gauge @Bridgman TS
12686976	N-TS-BRIDGMANTS-SI-BLDG A	10/03/2013	BLDG- 2 Exit doors require caulk
12686967	N-TS-BRIDGMANTS-SI-EN-SPILT5	10/03/2013	ENV- T15 containment curb requires caulk
12686977	N-TS-BRIDGMANTS-SI-BLDG A	10/03/2013	HVAC- A/C Not working
12160981	N-TS-BRIDGMANTS-CN-BRIDRTU	04/23/2013	T6 TAP CHANGER INDICATION
12160346	N-TS-BRIDGMANTS-TF-T5	04/23/2013	Bridgman T5 DC ground
12032312	N-TS-BRIDGMANTS-BR	12/12/2012	Bridgman/Highlevel Nomenclature
11941390	N-TS-BRIDGMANTS-SI-BLDG A	11/12/2012	Roof grounding required
11982533	N-TS-BRIDGMANTS-TF-T6	11/28/2012	Bridgman T6 low oil
11725780	N-TS-BRIDGMANTS-SI-BLDG A	09/16/2012	ELIGHTS-Batteries need replacing

11794028	N-TS-BRIDGMANTS-TF-T6	10/02/2012	Bridgman TS T6 Cooling Oil Pump #1
11144277	N-TS-BRIDGMANTS-TF-T6	04/25/2012	Bridgman TS Ct connection hot spot
10800600	N-TS-BRIDGMANTS-TF-T14	11/21/2011	Bridgman T14 Loss of cooling alarm
10723412	N-TS-BRIDGMANTS-SI	08/03/2011	Bridgman TS Fire Panel Malfunction
10721168	N-TS-BRIDGMANTS	07/27/2011	20260 Bridgman TS ARC FLASH LABELS
10667272	N-TS-BRIDGMANTS-TF-T6	03/17/2011	Bridgman T6 T/C breather oil leak
10619035	N-TS-BRIDGMANTS-TF	11/24/2010	Investigate Noise Complaint Bridgman TS
10516708	N-TS-BRIDGMANTS-CA-T14YB	06/13/2010	T14YB hot spots Bridgman
10502400	N-TS-BRIDGMANTS-TF-T14	05/10/2010	S3-EMD-BRIDGEMAN TS-T14 DIFFERENTIAL
10483308	N-TS-BRIDGMANTS-SI-YA	04/01/2010	Bridgman TS Yard Lighting
10286163	N-TS-BRIDGMANTS	04/08/2009	Cap & Pin Insulator Survey
10366508	N-TS-BRIDGMANTS	10/05/2009	T14 FIRE DETECTION NOT CONNECTED
10366507	N-TS-BRIDGMANTS-TF-T14	10/05/2009	T14 Y WINDING TEMP GAUGE
10357665	N-TS-BRIDGMANTS-TF-T12	09/18/2009	BRidgman TS T12 One cooling fan seized
10007436	N-TS-BRIDGMANTS-TF-T11	05/31/2008	Bridgman TS T11 Cooling Fan

3.10 Asset Centric Program Work

The following station equipment has been previously identified in Asset Centric Programs prior to the adoption of the Station Centric planning model:

Func. Location	Asset Class	Age	Condition	Demographics	Economics	Performance	Utilization	Criticality	Composite	Investment Description
N-TS-BRIDGMANTS	TS	62	34	84	18	32	38	1	36	Nuisance Wildlife Control - Capital Solutions
N-TS-BRIDGMANTS-TF-T5	Transformer: Step-down_115 kV	63	65	100	30	35	37	21	51	Transformer replacement program
N-TS-BRIDGMANTS-TF-T6	Transformer: Step-down_115 kV	60	20	100	42	50	37	21	41	Transformer replacement program

4.0 ON-SITE STATION ASSESSMENT

Randy Tibben	Network Mgmt Engineer	TXSustainmentCapitalPlanning
Michael Xavier	Sr.Network Mgmt Engineer	TXSustainmentCapitalPlanning
Tanya Ryzhova	Network Mgmt Engineer	TXSustainmentCapitalPlanning

Issues found:

Notes:

5.0 RECOMMENDATIONS

Main Plan Overview

Asset / Infrastructure	Action	Reason/Rationale	Risk
T11, T12, T13 (including NGR's and surge arresters)	-replace all units including NGR's and surge arresters - fire & noise barriers likely required. To be assessed - spill containment upgrade necessary	-units are running beyond expected service life increasing the probability of failure. -condition of all units is declining with past visible oil leaks. - secondary surge arresters are old porcelain type. - NGR's required for new standard transformers. - spill containment and fire/noise barriers not up to standard.	High
T15 NGR (and HV SA)	-apply NGR as/when appropriate if not already being planned -HV SA may need to be respect due to address TOV.	- to eventually properly ground transformer to allow for eventual removal of grounding transformer at High Level.	Med
T11, T12, T13 Transformer high-side and low-side disconnects	- to be replaced	- declining condition - potential layout change to accommodate new transformers will likely require relocation of these items.	High
SS2 and high-side disconnect	-replace and put in load interrupter also	- SS2 advanced age and poor condition - potential layout change will likely require removal and relocating this equipment.	High
SS1 high-side equipment	-apply high-side fused disconnect and load interrupter	- to bring up to current standards.	High
GT1	-permanently remove when possible	-all new standard transformers have some form of secondary grounding	Med
Current limiting reactors	-will require existing CLR's until three-supply High Level brickclads replaced	- potential layout change may require relocating CLRs.	Med
Potential transformers	- **AR 23630** has replaced 6 sets of delta PT's (T11X, T11Y, T12X, T13X, T13Y and T14X). These should be reused, if feasible, and relocated if necessary. - also replace T14Y and T12Y PTs.	- all units are older style oil-filled units likely containing PCBs. - potential layout change will likely require removal and relocation.	High
Insulators	- for entire station, replace all old porcelain strain insulators with glass-type. - for entire station, replace all cap&pin insulators with station post-type.	- can visually detect early failure of glass strain insulators and they maintain their mechanical strength when sheds may fail. - cap&pin insulators suffer from 'cement growth" failures.	High
Station service switchgear	- replace with standard DESN AC SS transfer scheme. Clean up and remove unused/unnecessary panels and fused disconnects, etc.	- install transfer scheme consistent with new standard and to allow loading of both SS transformers.	High
Revenue Metering	- AR 23630 has installed 8 sets of revenue metering IT's (T11-T14). These should be re-used, where feasible, and relocated if necessary.	-upgrade to current metering standards	High
SS Metering	- PCT Solutions to assess need for station service metering.	-no SS metering currently exists.	Med
Site drainage	- assess condition of drainage infrastructure and upgrade as required.	- Want to ensure drainage system is in good condition and meets standards since yard will be significantly dug up.	High
Existing structures and footings that will remain / be re-used	- For old structures and footings that will be remaining, assess condition. Perform remediation and life extension measures as required.	- to prolong the useful life of existing structure where possible.	High
Tunnel	- preference is to install standard control cable trench and remove old tunnel. However, if continued use is necessary, then remediate to ensure structurally	- certain members appears to be decaying and remediation work would be necessary if tunnel kept. - tunnel may possibly interfere with spill containment or cable	High

	sound.	trenches and new drainage piping.	
Oil Building Removal	-remove old underground oil building	-no longer required. Should be cleaned up and removed. -space will be freed up.	High
Heritage Building	- assess condition of building and how much it would be to remediate or partially remediate for potential use. Assess feasibility of housing 13.8kV switchgear in the building.	- six H1 brickclad breakers/switchgear are at an advanced age and not arcproof. It is strongly recommended to replace this switchgear and preferred to relocate within Heritage building, if feasible, at Bridgman TS which is a H1 property.	High
Animal Mitigation	- apply all animal mitigation techniques at Bridgman (ie. cover up and electric fence barrier)	- lessen risk of animal contact outages	High
Fence/Security	- engage Physical Security group about Bridgman security needs	- Fence may need to be removed to accommodate work and new facilities. Is standard chain link fence or an opaque wall recommended?	High
32 L13W-34	-replace at Development & OGCC request with a circuit switches (Lines Sustainment will scope and fund this).	- this is a very old ABS which requires replacement.	High
High Level A1A2 and A7A8 switchgear	- Preference is to install new H1 A1A2 and A7A8 switchgear at Bridgman TS in heritage building, if feasible.	- these six H1 brickclad breakers / switchgear are at an advanced age and not arcproof. Old (now redundant) switchgear would remain I/S at High Level and continue to be maintained until THESL is ready replace the full lineup.	High

6.0 REFERENCE SOURCES

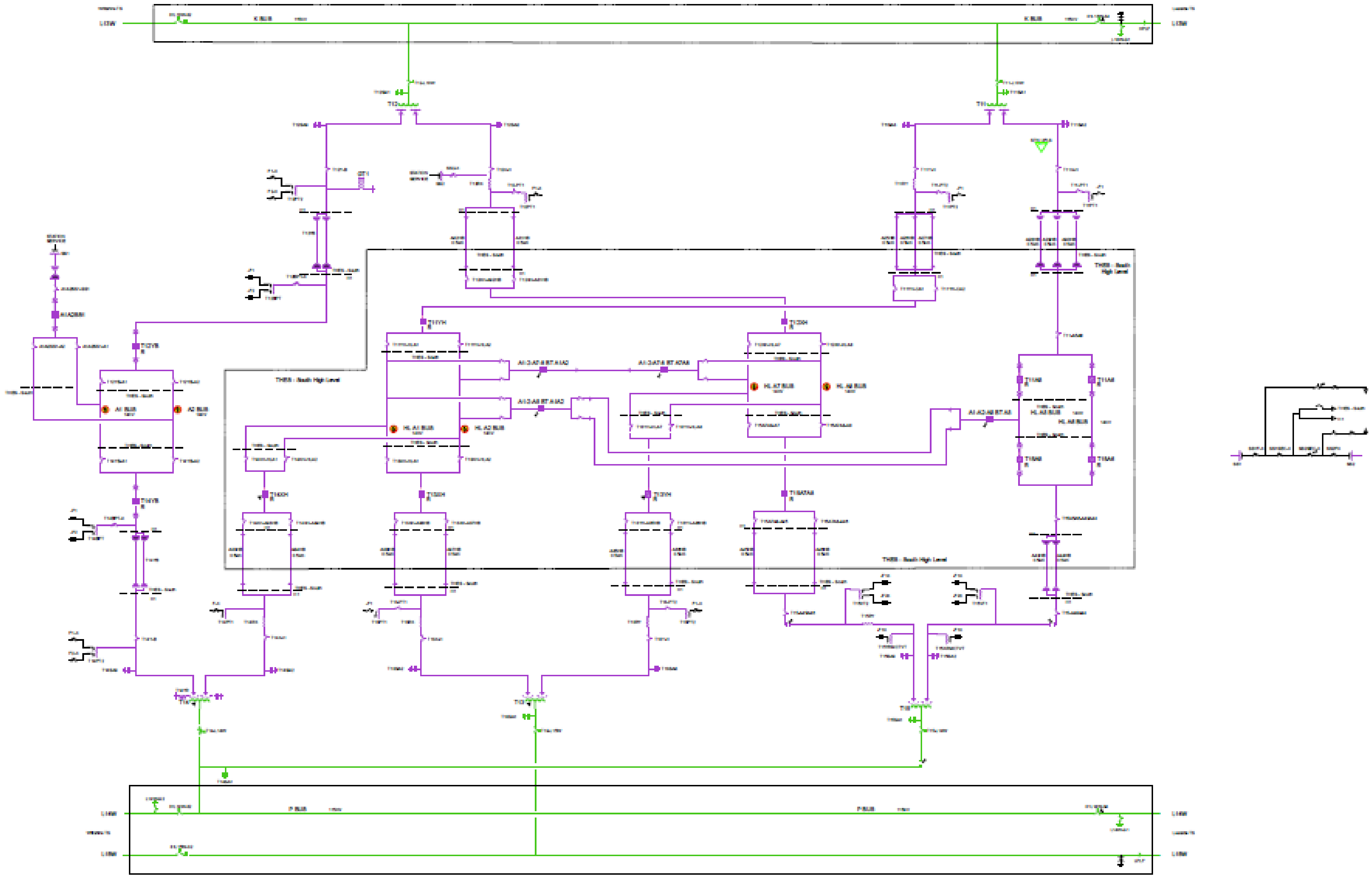
Bibliography

[1] Hydro One Networks Inc., "Station Fault Current Ratings," 2014. [Online]. Available: https://teams.hydroone.com/sites/TPD/TPD/ss_pd/Short Circuit/Surveys/Breakers.

[2] "Hydro One Networks; Stranded Load May 2013," [Online]. Available: https://teams.hydroone.com/sites/gridops/NOD/OP/Shared Documents.

[3] Conestoga-Rogers & Associates, "Hydro One Station Spill Risk Model," Mississauga, 2011.

APPENDIX 1 – BRIDGMAN TS OPERATING DIAGRAM



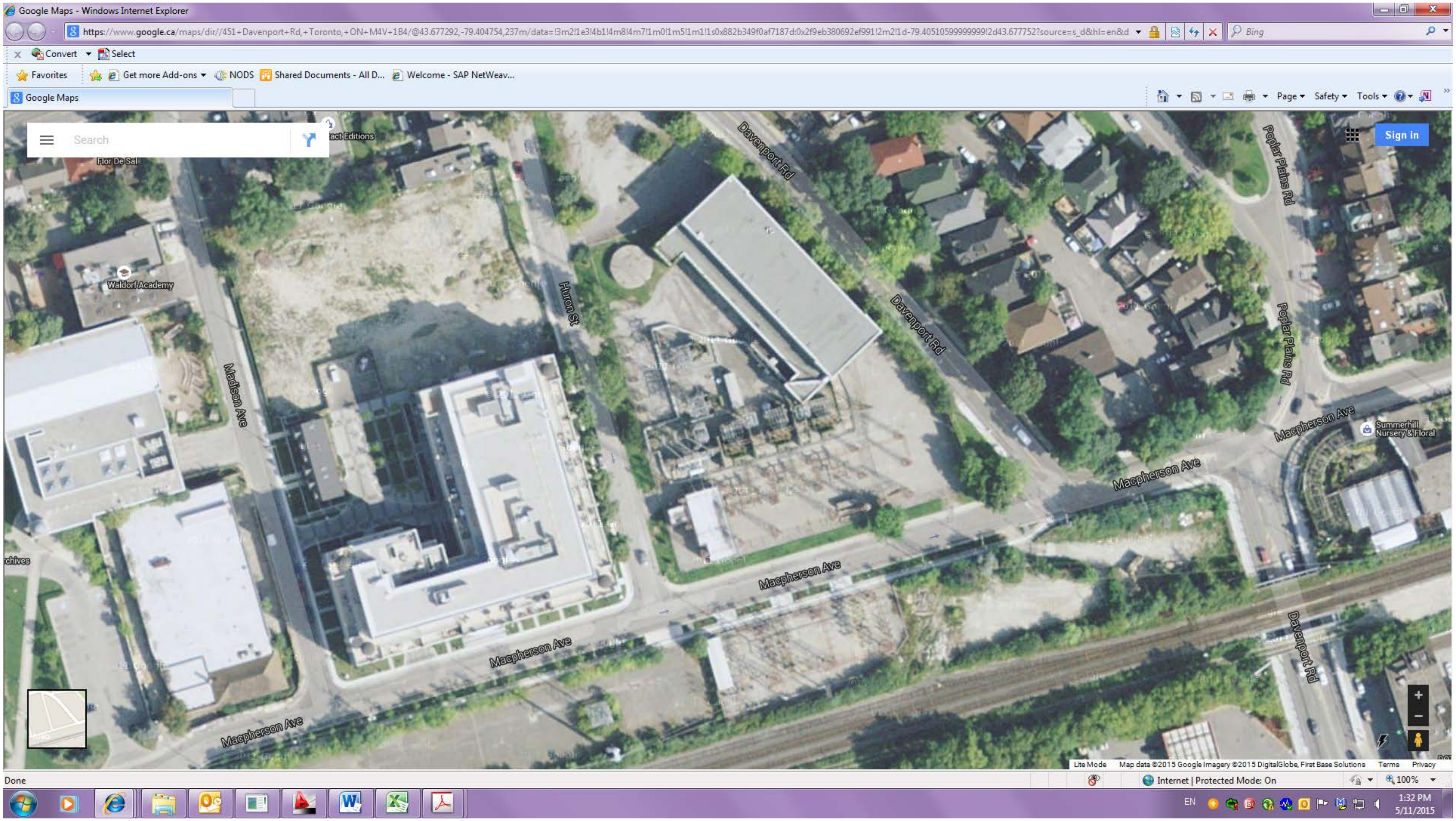
APPENDIX 2

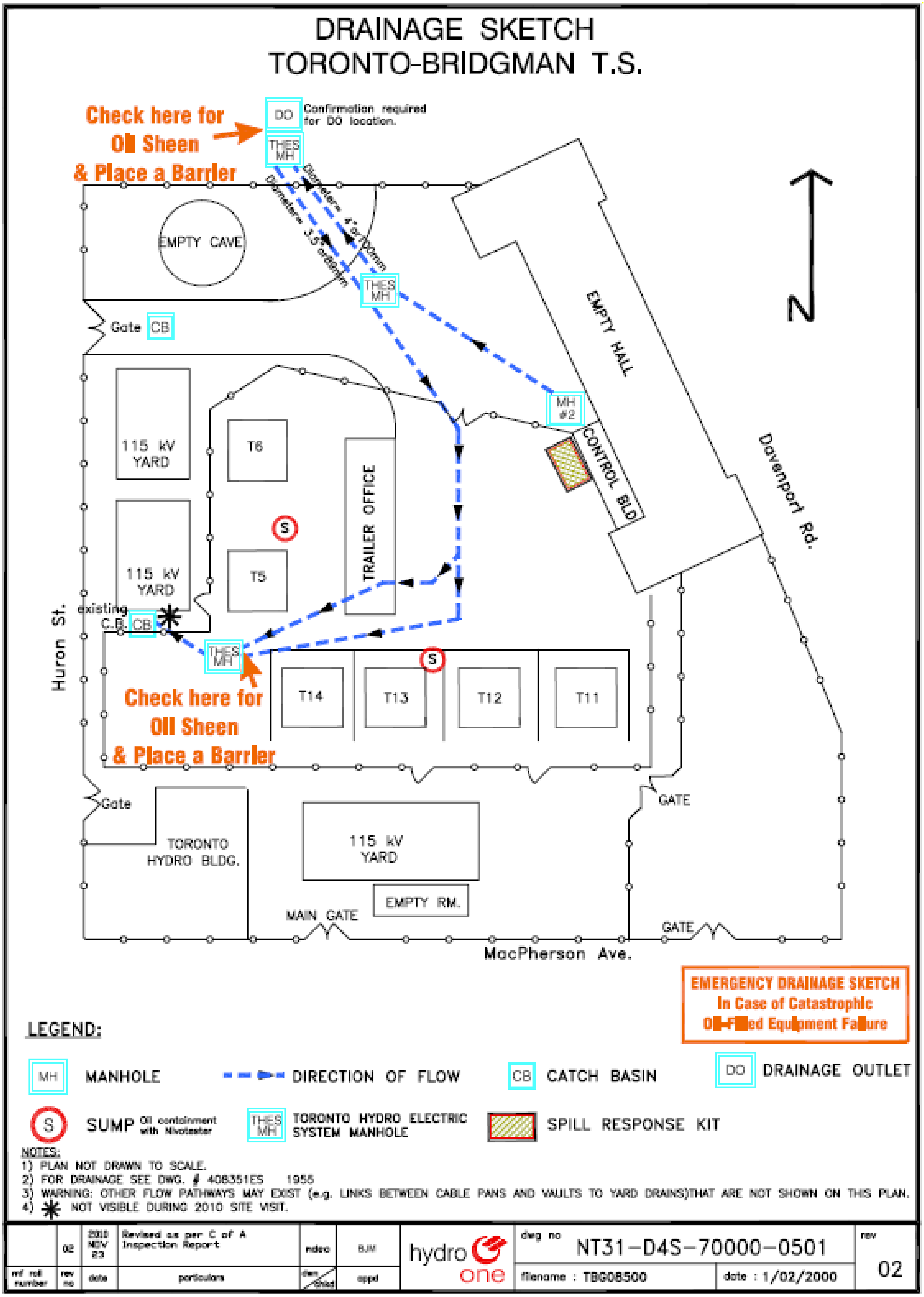
TEST	1/1/2010	*42136*	4/30/2015							
MCTYPE	MCID	OUTDATE	OUTIME	ODURALL_HR	PCAUSE	DESCRIPT	OUTURG	OUTEXT	STANAME	REMARK
Breaker	NT31T11YH	08-Dec-12	14:30	0.17	7NPR	Non Pwr Eqpt-Prot-Relay (General)	FA	CC	BRIDGMAN TS	IBO OCCURED - UNKOWN CAUSE
Breaker	NT31T11YH	11-Apr-10	22:37	7.00	7NCKG	Non Pwr Eqpt-Control-Breaker-Pallet Switch Defect	FM	CC	BRIDGMAN TS	CANNOT CLOSE-REPAIR PALLET SW
Breaker	NT31T13XH	27-Nov-12	21:34	11.47	1MK	Main Pwr-Breaker Equipment	FM	CC	BRIDGMAN TS	SMOKE IN THE SECONDARY WINDING
Bus	NT41A1A2	13-Feb-15	10:18	0.07	4FS	Power System Configuration-Series Connection	FA	CCT	BRIDGMAN TS	NT31T14 TRIP
Transformer	NT31T11	22-Apr-15	15:46	14.32	6A	Foreign Interference-Animals	FA	CCT	BRIDGMAN TS	RACCOON CONTACT
Transformer	NT31T11	14-Feb-15	13:20	0.57	4FO	Power System Configuration-Operations Requirement	FM	CCT	BRIDGMAN TS	PROT FUNCTION TESTING
Transformer	NT31T11	31-Jan-15	00:35	23.42	8	Unknown	FA	CCT	BRIDGMAN TS	FALSE TRIP = UNKNOWN REASON
Transformer	NT31T11	28-Jan-15	07:42	61.25	8	Unknown	FA	CCT	BRIDGMAN TS	UNKNOWN REASON - FALSE TRIP
Transformer	NT31T11	15-Apr-14	20:10	0.87	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L13W TRIP
Transformer	NT31T11	11-Apr-14	08:08	0.23	4FS	Power System Configuration-Series Connection	FM	CCT	BRIDGMAN TS	L13W O/S - NA34KL13 CLEARANCE
Transformer	NT31T11	06-Feb-13	12:22	68.77	6A	Foreign Interference-Animals	FA	CCT	BRIDGMAN TS	RACOON CONTACT-SECONDARY SIDE
Transformer	NT31T11	05-Nov-12	11:23	3.88	4FS	Power System Configuration-Series Connection	FM	CCT	BRIDGMAN TS	L13W LINE TRIP-MANUALLY
Transformer	NT31T11	23-Sep-12	11:14	49.28	4FU	Power System Configuration-Customer or Other Utility	FA	CCT	BRIDGMAN TS	TORONTO HYDRO X CABLE
Transformer	NT31T11	30-Jul-11	20:41	4.40	4FS	Power System Configuration-Series Connection	FM	CCT	BRIDGMAN TS	L13W
Transformer	NT31T11	18-Sep-10	16:47	5.05	4FZ	Power System Configuration-	FA	CCT	BRIDGMAN	NT9T1-H1 FALSHOVER

						Common Trip Zone			TS	WHEN CLOSIN
Transformer	NT31T11	10-Jan-10	11:26	7.70	4FU	Power System Configuration-Customer or Other Utility	FM	PCS	BRIDGMAN TS	THES REQUEST
Transformer	NT31T12	18-Apr-15	06:31	2.17	7NP	Non Pwr Eqpt-Protection System (General)	FA	CCT	BRIDGMAN TS	INCORECT PROT SETTINGS
Transformer	NT31T12	31-Mar-15	17:47	3.50	4FU	Power System Configuration-Customer or Other Utility	FA	CCT	BRIDGMAN TS	CUSTOMER FAULT @ THES
Transformer	NT31T12	27-Sep-14	18:25	113.93	8	Unknown	FA	CCT	BRIDGMAN TS	UNKNOWN REASON
Transformer	NT31T12	16-Apr-14	19:45	40.73	6A	Foreign Interference-Animals	FA	CCT	BRIDGMAN TS	RACCOON CONTACT
Transformer	NT31T12	15-Apr-14	20:10	0.93	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L13W TRIP
Transformer	NT31T12	11-Apr-14	08:08	0.23	4FS	Power System Configuration-Series Connection	FM	CCT	BRIDGMAN TS	L13W O/S - NA34KL13 CLEARANCE
Transformer	NT31T12	05-Nov-12	11:23	3.88	4FS	Power System Configuration-Series Connection	FM	CCT	BRIDGMAN TS	L13W LINE TRIP-MANUALLY
Transformer	NT31T12	30-Jul-11	20:41	4.40	4FS	Power System Configuration-Series Connection	FM	CCT	BRIDGMAN TS	L13W
Transformer	NT31T12	18-Sep-10	16:47	5.05	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	NT9T1-H1 FALSHOVER WHEN CLOSIN
Transformer	NT31T13	13-Feb-15	10:38	3.63	4DL	Power System Condition-(Over)Load	FA	PCS	BRIDGMAN TS	OVERLOAD
Transformer	NT31T13	31-Jan-15	00:15	0.45	7NPU	Non Pwr Eqpt-Prot-Undetermined Problem	FM	CCT	BRIDGMAN TS	CHANGING PROTECTION SETTINGS
Transformer	NT31T13	30-Jul-14	06:54	48.98	3D	Adv Environment-(Flying) Debris (General)	FA	CCT	BRIDGMAN TS	FLYING DEBRIS
Transformer	NT31T13	12-Jun-14	23:59	112.55	7NP	Non Pwr Eqpt-Protection System (General)	FA	CCT	BRIDGMAN TS	PILOT WIRE/BLIND SPOT PROT
Transformer	NT31T13	15-Apr-14	20:10	0.90	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L15W TRIP
Transformer	NT31T13	18-Oct-13	12:08	37.32	6A	Foreign Interference-Animals	FA	CCT	BRIDGMAN TS	SQUIRREL CONTACT
Transformer	NT31T13	30-Nov-12	23:47	58.22	8	Unknown	FA	CVT	BRIDGMAN TS	UNKNOWN CAUSE
Transformer	NT31T13	24-Feb-12	21:00	44.20	1MTDD	Main Pwr-Transformer Eqpt-Insul-Gas Tested OK	FM	CCT	BRIDGMAN	GAS ACCUMULATION-

									TS	CHECKED O.K.
Transformer	NT31T13	04-Jul-10	22:28	13.25	1TXD	Term Pwr Eqpt-Cable-Insulation Defect	FA	CCT	BRIDGMAN TS	THES CABLE FAULT
Transformer	NT31T13	10-Jan-10	11:26	7.70	4FU	Power System Configuration-Customer or Other Utility	FM	PCS	BRIDGMAN TS	THES REQUEST
Transformer	NT31T14	13-Feb-15	10:18	0.07	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T14	28-Jan-15	07:44	5.77	5WB	Human Element-Wiring Error-Installation	FA	CCT	BRIDGMAN TS	CT EIRING ISSUES-FALSE TRIP
Transformer	NT31T14	27-Nov-14	20:04	189.52	1TXA	Term Pwr Eqpt-Cable-Pothead Failure	FA	CCT	BRIDGMAN TS	R & B CABLES POTHEAD FAILURE
Transformer	NT31T14	25-Nov-14	20:16	18.95	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T14	15-Apr-14	20:10	0.95	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T14	26-Nov-12	19:37	0.10	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T14	15-Dec-11	11:55	0.28	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	NT31T6 FAULT
Transformer	NT31T14	25-Jul-11	20:03	119.78	7NPFA	Non Pwr Eqpt-Prot-Telecom-Equipment Failure	FA	CCT	BRIDGMAN TS	T14X P/W B/SPOT PROT.PROBLEM
Transformer	NT31T14	10-May-10	10:08	105.37	4FU	Power System Configuration-Customer or Other Utility	FA	CCT	BRIDGMAN TS	THES A33HB CABLE FAULT
Transformer	NT31T14	03-Mar-10	05:22	83.88	1TXD	Term Pwr Eqpt-Cable-Insulation Defect	FA	CCT	BRIDGMAN TS	T14X CABLE FAULT
Transformer	NT31T14	10-Jan-10	11:26	7.70	4FU	Power System Configuration-Customer or Other Utility	FM	PCS	BRIDGMAN TS	THES REQUEST
Transformer	NT31T5	27-Nov-14	20:04	1.78	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T5	25-Nov-14	20:16	18.95	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T5	15-Apr-14	20:10	0.93	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T5	06-May-13	12:01	1.48	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	FM	CCT	BRIDGMAN TS	HIGH OIL LEVEL ALARM
Transformer	NT31T5	05-May-13	14:10	2.02	7NA	Non Pwr Eqpt-Annunciation/Alarm Circuit	FM	CCT	BRIDGMAN TS	LOW OIL ALARM

Transformer	NT31T5	16-Mar-13	06:08	72.98	4FU	Power System Configuration-Customer or Other Utility	FA	CCT	BRIDGMAN TS	THES A43HB/A44HB CABLES FAULT
Transformer	NT31T5	26-Nov-12	19:37	0.10	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T5	12-Aug-12	00:58	39.72	4FU	Power System Configuration-Customer or Other Utility	FA	CCT	BRIDGMAN TS	P/W PROT FOR THES CABLE FAULT
Transformer	NT31T5	15-Dec-11	11:55	0.28	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	NT31T6 FAULT
Transformer	NT31T5	27-Jul-10	17:58	41.98	4FU	Power System Configuration-Customer or Other Utility	FA	CCT	BRIDGMAN TS	THES SECONDAY CABLE FAULT
Transformer	NT31T6	13-Feb-15	10:18	1837.70	1MTB	Main Pwr-Transformer Eqpt-Winding (General)	FA	CCT	BRIDGMAN TS	TRANSFORMER FAILURE-GAS IN OIL
Transformer	NT31T6	27-Nov-14	20:04	1.78	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T6	25-Nov-14	20:16	18.95	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T6	15-Apr-14	20:10	0.85	4FZ	Power System Configuration-Common Trip Zone	FA	CCT	BRIDGMAN TS	L14W TRIP
Transformer	NT31T6	09-Mar-13	21:05	31.42	8	Unknown	FA	CCT	BRIDGMAN TS	UNKNOWN DIFF/PILOT/BLIND PROT
Transformer	NT31T6	27-Jan-13	01:20	118.67	8	Unknown	FA	CCT	BRIDGMAN TS	UNKNOW CAUSE FOR DIFF TRIP
Transformer	NT31T6	26-Nov-12	19:37	100.38	8	Unknown	FA	CCT	BRIDGMAN TS	UNKNOWN CAUSE
Transformer	NT31T6	28-Oct-12	21:10	74.83	1MTDB	Main Pwr-Transformer Eqpt-Insul Oil Leak	FM	CCT	BRIDGMAN TS	LOW OIL LEVEL IN TRANS TANK
Transformer	NT31T6	15-Dec-11	11:55	30.05	1TXD	Term Pwr Eqpt-Cable-Insulation Defect	FA	CCT	BRIDGMAN TS	THES SEC.A46HB CABLE FAULT
Transformer	NT31T6	17-Mar-11	11:58	5.28	1MTDB	Main Pwr-Transformer Eqpt-Insul Oil Leak	FM	CCT	BRIDGMAN TS	REPAIR TAP CHANGER OIL LEAK
Transformer	NT31T6	18-Jul-10	11:52	50.63	1TXD	Term Pwr Eqpt-Cable-Insulation Defect	FA	CCT	BRIDGMAN TS	THES CABLE FAULT
Transformer	NT31T6	12-Jan-10	20:02	90.60	4FU	Power System Configuration-Customer or Other Utility	FA	CCT	BRIDGMAN TS	THES T6 SEC.CABLE FAULT


Google Maps - Windows Internet Explorer
Google Maps
Search
Sign in
Davenport Rd
Poplar Plains Rd
Huron St
Madison Ave
Waldorf Academy
Macpherson Ave
Summerhill Nursery & Floral
Flor De Sal
Done
Internet | Protected Mode: On


DRAINAGE SKETCH
TORONTO-BRIDGMAN T.S.
Check here for
Oil Sheen
& Place a Barrier
DO
Confirmation required for DO location.
THES MH
Diameter= 4" or 100mm
Diameter= 3.5" or 89mm
EMPTY CAVE
Gate
CB
EMPTY HALL
MH #2
CONTROL BLD
Davenport Rd.
115 kV YARD
T6
TRAILER OFFICE
S
115 kV YARD
T5
existing C.B.
CB
Huron St.
THES MH
Check here for
Oil Sheen
& Place a Barrier
S
T14
T13
T12
T11
GATE
Gate
TORONTO HYDRO BLDG.
115 kV YARD
EMPTY RM.
MAIN GATE
GATE
MacPherson Ave.
EMERGENCY DRAINAGE SKETCH
In Case of Catastrophic
Oil-Filled Equipment Failure
LEGEND:
MH MANHOLE
DIRECTION OF FLOW
CB CATCH BASIN
DO DRAINAGE OUTLET
S SUMP Oil containment with Nivotester
THES MH TORONTO HYDRO ELECTRIC SYSTEM MANHOLE
SPILL RESPONSE KIT
NOTES:
1) PLAN NOT DRAWN TO SCALE.
2) FOR DRAINAGE SEE DWG. # 408351ES 1956
3) WARNING: OTHER FLOW PATHWAYS MAY EXIST (e.g. LINKS BETWEEN CABLE PANS AND VAULTS TO YARD DRAINS)THAT ARE NOT SHOWN ON THIS PLAN.
4) ✱ NOT VISIBLE DURING 2010 SITE VISIT.
02
2010 NOV 23
Revised as per C of A Inspection Report
ndeo
BJM
mf roll number
rev no
date
particulars
dwn chkd
appd
hydro one
dwg no
NT31-D4S-70000-0501
filename : TBG08500
date : 1/02/2000
rev
02

OEB INTERROGATORY #80

Reference:
TSP-01-04-14 p. 28

Interrogatory:
At the above noted reference, BCG stated the following:

In developing projects, best practice is to evaluate among different types of potential options to ensure asset life cycle costs are optimized. Hydro One conducts this analysis as it is developing projects, with a focus on stations assets given the lack of maintenance or refurbishment alternatives for lines assets. Hydro One conducts a combination of qualitative and quantitative analysis to evaluate among different capital spending options and among capital and OM&A options. For transformers, NPV models are used to assess capital vs. OM&A tradeoffs, while for other types of stations assets, qualitative analysis is conducted to evaluate the risks and benefits of different capital and OM&A scenarios

a) Please provide typical documentation for capital versus OM&A tradeoff analysis for the following asset classes:
    i. Power Transformers
    ii. Circuit Breakers
    iii. Protection, Control & Telecom Infrastructure
    iv. Overhead Transmission Conductors

Response:
a) Please refer to OEB-019, part f.

OEB INTERROGATORY #81

Reference:
TSP-01-04-14
Exhibits 23, 24, 25 and 27

Interrogatory:

a) Based on Exhibits 23, 22, 25 and 27 referenced above, it appears that all steps of Hydro One's asset management and investment planning process are documented. For all of the investment planning projects (or at least the major asset classes of Power Transformers, Circuit Breakers, Protections, Overhead Transmission Conductors), please provide a table (preferably in MS Excel format) listing the following:

i. Project Identifier
ii. Project Name
iii. Asset Class
iv. Project Cost
v. Risk: For each of the three risk categories (Safety, Environmental, Reliability) before and after each of the relevant asset management steps where these values change (e.g. Candidate Investment Development, Scoring, Calibration, Initial Prioritization, Challenge Sessions, Executive Review etc.)
    1. Baseline Probability of Failure
    2. Baseline Consequence of Failure
    3. Baseline Risk
    4. Mitigated Probability of Failure
    5. Mitigated Consequence of Failure
    6. Mitigated Risk (Residual Risk)
    7. Mitigated Risk Units

vi. Project cost
vii. Primary Project Driver
viii. Flags before and after each of the relevant asset management steps where these values change (e.g. Candidate Investment Development, Scoring, Calibration, Initial Prioritization, Challenge Sessions, Executive Review, etc.)

Response:

a) i-iv:

Investment Summary Documents for major asset classes are summarized below:

Project Identifier	Project Name	Asset Class	3 Year (2020-2022) Test Period Cost ($M)
SR-01	Air Blast Circuit Breaker Replacement Projects	Circuit Breaker	366.2
SR-02	Station Reinvestment Projects	Transformers, Breakers, Switchgear and Protection and Control systems	352.9
SR-03	Bulk Station Transformer Replacement Projects	Power Transformers	157.5
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	Station Switchgear and Ancillary Equipment	90.0
SR-05	Load Station Transformer Replacement Projects	Power Transformers	352.4
SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	Station Switchgear and Ancillary Equipment	97.5
SR-07	Protection and Automation Replacement Project	Protections	28.0
SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	Overhead Transmission Conductors	298.4
SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	Overhead Transmission Conductors	237.3

v. The baseline risk and mitigated risk levels for the major asset classes by Investment Summary Document (ISD) are provided in Figure 1 below. The risk mitigation before and after each step of the process did not change across steps. Refer to Figure 2 and 3 for a more detailed view of the Environment and Safety risk levels. No adjustments to risk were made during the Investment Planning Process stages.

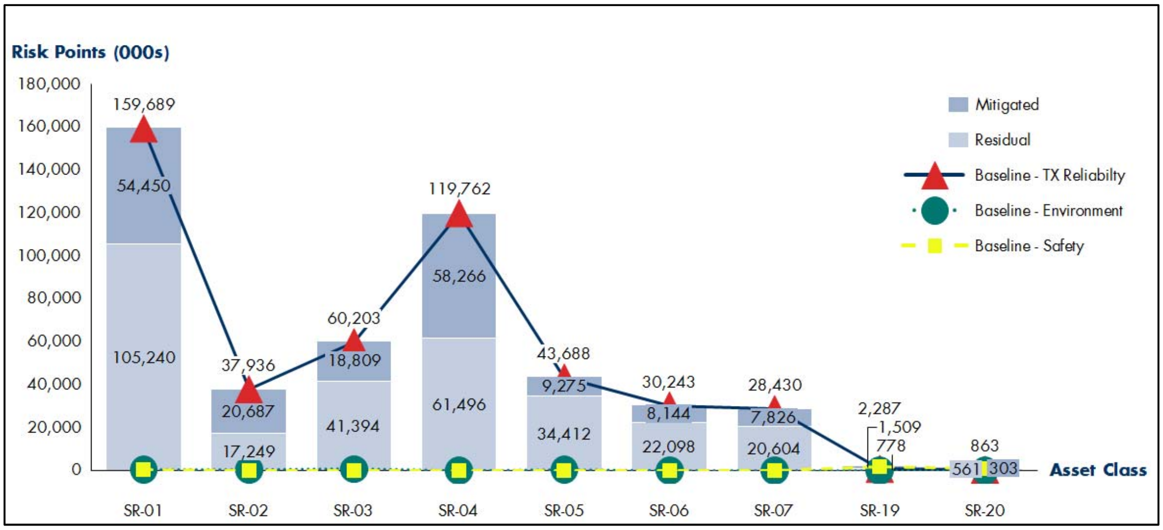


Figure 1: Baseline and Mitigated Risk per ISD

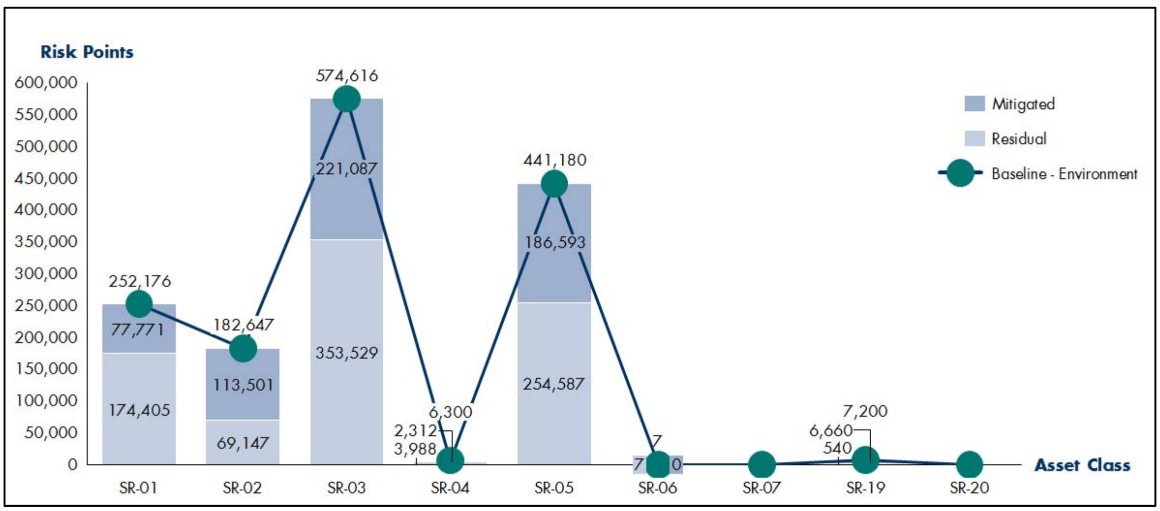


Figure 2: Baseline and Mitigated Environment Risk per ISD

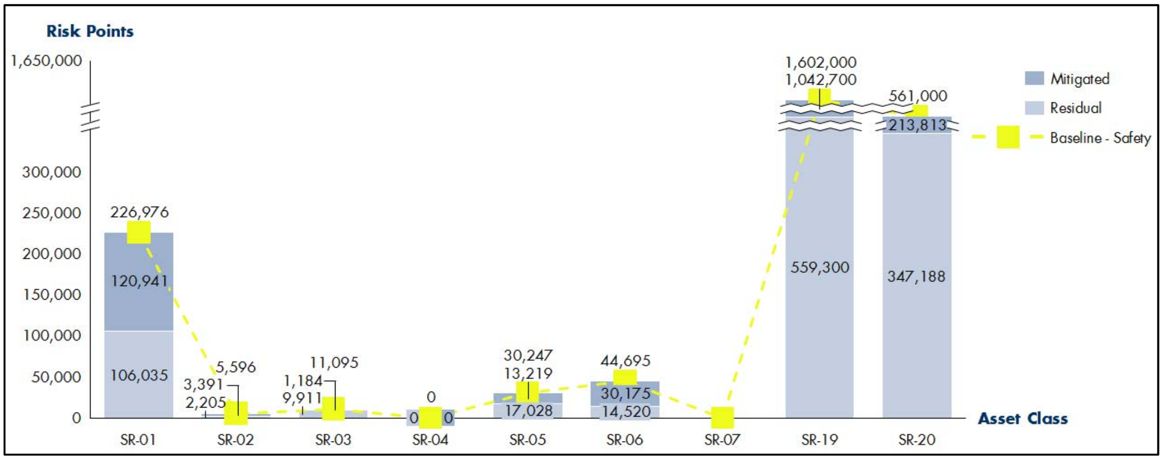


Figure 3: Baseline and Mitigated Safety Risk per ISD

vi. Refer to ISD-SR-01 to ISD-SR-07, SR-19 and SR-20

vii. Refer to ISD-SR-01 to ISD-SR-07, SR-19 and SR-20

viii. Table 1 below outlines the types of flags used in each Investment Summary Document (ISD). The flags before and after each step of the process did not change across steps. Flags are identified on an individual investment candidate basis and may not apply to every investment contained with an ISD.

Table 1: Asset Class Flags

Flag Type	Asset Class								
	SR-01	SR-02	SR-03	SR-04	SR-05	SR-06	SR-07	SR-19	SR-20
Immediate / Short-Term Compliance	X				X				
Third Party Requests									
Contractual									
In-Flight	X	X	X		X	X		X	
Customer Engagement	X	X	X	X	X	X	X	X	X
Productivity									
Corrective Maintenance/Demand Replacements									
Preventive Maintenance/System Renewal	X	X	X	X	X	X	X	X	X
Strategic	X								
Political Commitments									

OEB INTERROGATORY #82

Reference:
TSP-01-04-15 p. 2

Interrogatory:
At the above noted reference, Hydro One stated the following:

Investment Development
Hydro One's transmission assets are replaced as condition warrants through rigorous testing. However, a backlog of asset condition testing has developed for assets such as conductors and shieldwire, where a large portion of the asset base is approaching it's Expected Service Life ("ESL").

a) The EPRI report "Derivation of Overhead Conductor Hazard Function" (Exhibit B-1-1 Attachment 4) states on page 3-30 "Even with these more homogeneous (though smaller) data subsets, Age does not appear to have a significant correlation with overall condition or any of the constituent conditions (assessment factors)" and on page 3-41 "The investigations focusing on smaller and more homogeneous data sets revealed no clear correlations between overall condition and age, similar to the findings for the larger data set." Please confirm that conductor demographics are not driving the urgency of the expanded conductor replacement program.

b) Has new information been obtained since Hydro One's most recent prior cost of service application that justifies significantly increased annual conductor replacement expenditures?

Response:
a) The EPRI report relates age to condition using Weibull distribution modeling (Exhibit B-1-1, TSP Section 1.4, Attachment 4, pages 81-98), and forecasts increased high risk conditioned conductor population going forward. This finding reinforces the need for Hydro One to proactively engage in conductor replacement, to ensure that high risk conductor assets are managed in a timely manner that maintains system reliability and limits the safety risks. All conductor replacements are driven by verified condition and not age or location. As discussed in ISD SR-19, 3,680 km of conductor or 13% of the overall fleet has been verified to be in high risk condition, with 2,127 km planned to be replaced during the planning period.

b) The EPRI Report at Exhibit B-1-1, TSP Section 1.4, Attachment 4, pages 91-94 forecasted an increased population of high risk conductors in the Hydro One transmission system over the next 20 years and therefore requires increasing the pace at which verified deteriorated conductors are replaced. Failure to address this issue proactively would result in unmanageable risk and an unmanageable number of deteriorated EOL assets in later years.

OEB INTERROGATORY #83

Reference:
TSP-01-04-15 p. 5 TSP-03-03 p. 4

Interrogatory:
At the second reference above, Hydro One stated the following:

System Renewal investments will increase 5.5% over the course of this TSP, with investment in both stations and line refurbishment seeing a 5.7%, and 5.5% increase over the plan, respectively. The objective over the planning period is to return to top quartile reliability performance and this level of spending is designed to accomplish this objective.

a) How were the reliability performance targets shown in Figure 2 selected?

b) How was the top quartile performance target determined? Is this an internal Hydro One target or was this target set by others?

c) If the target is set by others, were they aware at the time that such a large capital spending increase would be necessary to meet the performance target?

d) What is the basis for confidence that the proposed spending is necessary to deliver the target performance levels? In other words, how was the performance outcome calculated based upon the proposed spending levels?

e) Given that cost concerns are the biggest issue for most ratepayers, how did Hydro One determine that a top quartile performance target is appropriate for such a large system covering such a range of load densities, geographies and climatic regions?

Response:

a) The objective is to return to top quartile reliability, which includes managing the condition of the assets to continue to reliably perform their functionality. In Figure 2, the values are estimated end-of-plan outcomes. These outcomes were based on the initial allocation work done early in the planning process.

b) The top quartile target is a strategic business objective to achieve top tier reliability performance and validated consistent with the customer engagement process. This is an internal Hydro One target based on Hydro One's interpretation of customers expressed preference for reliable service. The customer engagement survey feedback was clear that reliability performance is a priority outcome.

c) Please refer to b) above.

d) The performance outcome was calculated based upon the last 10 years of performance data and a high level target to achieve 2% improvement per year. The performance outcome is expected to be met through the integration of key reliability initiatives, referenced in OEB-018, part c.)

e) Cost was not the biggest issue raised through the customer engagement process; please refer to Exhibit B, Tab 1, Schedule 1, Section 1.3 for a listing of customers' top priorities. Refer to b, above.

OEB INTERROGATORY #84

Reference:

TSP-01-05

Figure 1- Evolved Electricity Transmitter Scorecard & Targets- Hydro One Networks Inc.& EB-2016-0160/Exh B2/Tab 1/Sch 1/Table 2

Interrogatory:

In the previously proposed transmission scorecard, which is the second reference above, under Cost Control, Sustainment Capital was made up of seven Tier 3 Metrics, two of which are Line Clearing Cost per km and Brush Control Cost per Ha.

a) Have the other five metrics been removed or incorporated elsewhere?

Response:

a) Please refer to AMPCO-018.

OEB INTERROGATORY #85

Reference:

TSP-02-02 p. 11
Figure 5, p. 12, Figure 6 and p. 13, Table 4

Interrogatory:

a) Please confirm that both the forced outage duration (Figure 5) and forced outage frequency (Figure 6) has been declining over the same period that annual asset failure rates (Table 4) have been increasing.

b) Please explain this inverse correlation.

c) If redundancy is improving system reliability, are asset level risk evaluations being adjusted to account for the increasing redundancy?

Response:

a) Forced outage frequency and duration are confirmed as declining over the period. The rate of failures is confirmed as increasing over the time period.

b) Transformers can be forced out of service for multiple issues that are not the result of the complete failure of the unit. As examples transformers can be forced from service to top up the oil, to resolve a tapchanger issue or to address bushing defects. Complete transformer failure caused outages are a subset of the overall forced outages and may or may not be correlated with the forced outage rate at different points in time depending on how large the respective frequency and duration numbers are for the failed units at a given point in time.

c) Increased system redundancy is not a contributing factor to forecast reliability improvements. Overall system redundancy is not forecast to materially change over the plan period; differences in risk evaluations are adjusted and taken into account as part of the investment planning process.

OEB INTERROGATORY #86

Reference:
TSP-03-00 p. 4
Figure 1

Interrogatory:

a) Please provide the before and after risk scores for each of the 4 projects identified in Figure 1.

b) Please provide the before and after risk scores for each alternative considered for the 4 projects.

c) Given that the 4 projects identified in Figure 1 are starting with significantly different risk scores, please explain why they all made the priority project list.

d) Are there projects included in this filing for which the existing candidate investment scoring is in any of the green zones? If yes, please identify these projects.

e) Please provide a concrete example of the change in risk score for an asset located in a radial system that becomes redundant or networked. For example, please show before and after risk scores for a transformer that was initially in a radial installation that was later modified to become a redundant or networked installation.

Response:

a) Overall risk scores for the following 4 projects are as follows:

Project	Baseline Risk Score (Risk Points)	Residual Risk Score (Risk Points)
HV UG Cable - Replace H7L/H11L	36,000	4,200
Bruce B SS ABCB Replacement project	2,272,160	28,152
Bruce A TS: 500kV ABCB replacement and Yard Reconfiguration	1,043,700	630,204
John TS: HV/LV Station Rebuild	328,102	4,248

b) Refer to IR I-07-SEC-37

Witness: Bruno Jesus

c) Prioritization and Optimization within the Investment Planning Process is detailed within Exhibit B-1-1 TSP Section 2.1. Investments are prioritized within the preliminary plan based on risk mitigated per dollar where the efficiency of an investment is considered.

d) The following investments had baseline risk scores within the green zone. Additional rationale for these investments include mandatory criteria such as in-flight, compliance, or third party requests or discretionary considerations such as strategic, preventive or sustainment.

Investment Name
C21J: Connect Romney Wind Energy Centre
CMS Service Equipment
Construction Service Equipment
Corporate Services Transformation - Finance - CAP
CTS Service Equipment
Install DDRs for NERC Compliance
ITMC Backup Move to ISOC
PSR Replacement
Rayner CGS PRC-025 Compliance Update
Synchrophasors (PMU)
Dufferin TS: Revenue Metering Upgrade
Duplex TS: Revenue Metering Upgrade
Fleet Service Equipment
Forestry Service Equipment
HS&E Service Equipment
Leslie TS - M21, M25, M27, M28 KSO replace support
MTS Service Equipment
Nanticoke GS Disconnection
OGCC Office Remediation
Provincial Lines Service Equipment
Riverdale JCT x Overbrook TS: Build new A6R Tap
SAP Foundation Phase 2 - Finance -CAP
Stations Service Equipment
Strachan TS: Revenue Metering Upgrade

e) There are no examples where this instance exists.

OEB INTERROGATORY #87

Reference:

TSP-03-00, TSP-03-01, TSP-03-02, TSP-01-03
(1) Section 3.0, p. 5,
(2) TSP Section 3.1, p. 1
(3) TSP Section 3.2, p. 2
(4) TSP Section 1.3, p. 8

Interrogatory:

At the first reference above, Hydro One stated the following:

Overall spend: Hydro One's proposed budget envelope was set at a level below what was tested with customers, as evidenced in Sections 1.3 and 3.2 of this TSP. Hydro One agreed with customer feedback that this approach offered the appropriate balance between ratepayer costs and risk mitigation.

At the second reference above, Hydro One stated the following:

The proposed plan balances: (i) asset-related needs of the transmission system arising from age, condition and environmental and regulatory compliance requirements; (ii) customer needs and preferences relating to reliability; (iii) regional infrastructure and broader system needs to address system constraints, enable new load growth, and facilitate access and new connections to the transmission system; and (iv) impact on customer rates.

At the third reference above, Hydro One stated the following:

All business customer segments, particularly LDCs, prefer that investments be spread out over time, along with stable rate increases. This preference is due primarily to perceived affordability for ratepayers and the ability to plan ahead.

At the fourth reference above, Hydro One stated the following:
Cost was also raised at various times throughout the survey. The desire for good reliability at a competitive or low cost was universal.

a) Customers have consistently expressed that cost is their #1 concern (i.e. the desire for low cost was universal), yet Hydro One is proposing a 40% increase in capital spending in a low inflation environment with negative system load growth and good reliability performance. In this context, please explain how Hydro One's plan properly balances the 4 points listed above.

b) Did customers endorse a 40% increase in capital spending? Please provide evidence.

c) Regarding the pacing of investments (per the third reference above):
   i. Do customers demand stable rate increases, or would they be happier with flat or decreasing rates? Please provide evidence supporting this claim.
   ii. Is it more appropriate for this statement to read as: "Customers prefer that any unavoidable rate increases are at least stable"?
   iii. How has this customer demand been considered when developing Hydro One's proposed 40% capital spending increase?

<u>Response:</u>

a) The principles of asset management seek to manage assets to optimally meet the requirements of all stakeholder, including short-term outcomes and long-term, sustainable outcomes, through actions which will balance cost, performance, and risk. While customers have indicated that cost is a priority they have been very clear with respect to their needs as it relates to reliability. Hydro One has put forward an investment plan that takes into consideration a spending envelope that reflects customer feedback received in Exhibit B-1-1, Section 1.3 Attachment 1.

b) As indicated in Exhibit B, Tab 1, Schedule 1, Attachment 1, through clustered responses, customers generally endorsed a set of outcomes consistent with Scenario C, which:
   a. Extends investment plan in rate application currently before the Ontario Energy Board to 2023
   b. Maintains current level of sustainment capital investments affecting key assets
   c. Improves percentage of key assets beyond expected service life and decreases expected future investment requirements
   d. Includes a 5 year capital investment plan of $6.6B ($1.3B/year). This Application includes a 3 year capital investment plan of $3.9B ($1.3B/year) which is commensurate with Scenario C

e. Includes an average annual total bill impact for transmission connected customers of 0.42% over five years. This Application includes an average annual total bill impact for transmission connected customers of 0.5% over 2020 to 2022. When 2019 is accounted for, transmission connected customers will see a total bill impact of 0.4% over four years. This is commensurate with Scenario C

f. Includes an average annual transmission rate increase of 5.1% (not including load impact) over five years. The Plan will achieve these outcomes for a lower rate increase of 4.6% / year (not including load impact) from 2019-2022 which includes the OEB approved 2019 inflationary rate filing. This is commensurate with Scenario C

The table below shows the capital trajectory of the current application and the prior application, which was referenced in the customer engagement materials.

C	2017	2018	2019	2020	2021	2022	2023	2024
Capital Forecast ($M) – EB-2016-0160: Exhibit B1, Tab 3, Schedule 1	1,076.1	1,122.2	1,207.5	1,268.6	1,474.9			
Capital Forecast ($M) - EB-2019-0082, Exhibit B1, Tab 3, Schedule 1				1,192.2	1,317.7	1,369.6	1,369.6	1,369.6

c) Please see below:

i. Customers were not presented with a scenario of decreasing rates. Customers were presented limited and lower capital plans than the one currently proposed which highlighted that short-term reliability risk would increase, long-term reliability would deteriorate, and incremental future capital would be required resulting in higher future rate increases. With reference to these outcomes, customers indicated a preference towards level-rate increases in Scenario C, reflecting a balance between risk, cost and performance as shown in Exhibit B, Tab 1, Schedule 1, Section 1.3, Attachment 1.

ii. Customers have indicated a preference for stable rates over higher future rates.

iii. Hydro One has considered customers' preference towards improved performance outcomes and long-term sustainability, and has developed a transmission system plan that is intended to balance cost, risk and performance.

OEB INTERROGATORY #88

Reference:

TSP-03-01
(1) TSP Section 3.1, p. 6, Figure 2
(2) TSP Section 3.1, p. 8
(3) TSP Section 3.1, p. 11.

Interrogatory:

At the first reference above with respect to Figure 2, Hydro One stated the following:

Without the proposed renewal investment, the following percentages of major stations and lines assets are expected to reach the end of ESL by 2024: 41% of protections assets, 39% of transformers, 23% of breakers, and 13% of lines (conductors) assets.

At the second reference above, Hydro One stated the following:

3.1.1.1 Stations Renewal

The TSP includes stations renewal investments of $3.5 billion (53% of the total planning period forecast) to address transformers, circuit breakers, and protection, control and telecom equipment that are deteriorated as determined by condition assessments. Replacement is paced to maintain (though not lower) the proportion of assets beyond ESL over the planning period. Without the proposed investment, the proportion of assets beyond ESL will increase significantly, as set out in Figure 2.

At the third reference above, Hydro One stated the following:

3.1.1.1.1 Transformers

Hydro One plans to manage this risk by replacing an average of 22 transformers annually from 2020 to 2024 selected based on condition. With this replacement rate, Hydro One would be able to maintain the number of units that are beyond ESL to approximately the same level as of 2018, through to the end of 2029.

a) Is Figure 2 being used to justify the proposed increase in renewal spending?

b) Per the EPRI findings, please confirm that conductor ESL should be 90 years rather than 70 years.

c) Per the EPRI findings, please confirm that high and low pressure underground cable ESL should be 70 years rather than 50 years.

d) Given the recent large ESL step changes in the conductor and underground cable categories, please confirm that ESL is not an accurate indicator to justify asset replacements.

e) Is Hydro One using ESL as a justification for spending in the above referenced excerpts?

f) Please confirm that all assets in a particular age class do not degrade at the same rate, and that some assets will survive far beyond expected ESL in excellent or good condition.

Response:

a) In general, an asset is expected to reach End of Life (EOL) at their ESL. Assets operating beyond ESL generally have a higher likelihood of failing or being in poor condition. ESL, shown in Figure 2, is used to help anticipate potential replacement quantities in the long-term. Asset condition is the primary driver of replacement decisions and will be verified prior to the work being undertaken.

b) Confirmed.

c) Confirmed.

d) Please refer to part a).

e) Please refer to part a).

f) Confirmed. This is why asset condition is the primary driver of replacement decisions and will be verified prior to the work being undertaken.

OEB INTERROGATORY #89

Reference:
TSP-03-01 p. 11

Interrogatory:
At the above noted reference, Hydro One stated the following:

Transformers
Transformers are critical components used in electric power systems to convert power from one voltage level to another to facilitate supply to local distribution companies and industrial customers. Transformer forced outages have been a major cause of customer delivery point interruptions over the past 10 years, representing 13% of equipment caused events on Hydro One's transmission system. Through asset condition assessment, 17% of Hydro One's transformer fleet are rated high or very high risk based on oil testing results. Currently, 25% of Hydro One's transformer population is beyond its ESL. Assuming no replacements are undertaken, Hydro One anticipates that 280 units (39% of the transformer population) will exceed their ESL by 2024, and 332 units (46% of the population) will exceed their ESL by 2029.

a) Are "customer delivery point interruptions" and "events" used as synonymous terms in this explanation?

b) What percentage of events on Hydro One's system are directly caused by transformer failures?

c) How many customer delivery point interruptions were directly caused by transformer failures over the 10 year period?

d) What percentage of the "beyond ESL" transformers would be expected to fail between 2020 and 2024 based on past failure trends if they are not replaced?

e) Please confirm that the anticipated failure rate provided in answer d) above is not the same as the removal rate parameter derived in the EPRI transformer report (called a Hazard Rate in that report, although derived utilizing only uncategorized transformer removals data)

i. If not confirmed, please explain why Hydro One is unable to provide an expected transformer failure rate.

Response:

a) In this context events was used to describe individual delivery point interruptions.

b) Approximately 0.2% of delivery point interruptions were caused by a failure of a transformer. Delivery points can also be interrupted by other outages on transformers that are not the result of complete failure of the transformer.

c) Over the 10 year period 16 delivery point interruptions were attributed to the failure of a transformer.

d) According to Hydro One's transformer records presented at Exhibit B-1-1 TSP Section 2.2 page 12 and 13, 52% of failures were transformers that were beyond ESL. This ratio of failed beyond ESL transformers reflects Hydro One's proactive replacement and corrective activities, and is an appropriate baseline. However, it would be speculative to estimate future failures assuming no replacement as Hydro One does not have "run-to-failure" statistics. Such an approach to managing Hydro One's transformer fleet would be imprudent and would elevate safety and system risk.

e) It is confirmed that the Table 4 provided by Hydro One in the TSP document is transformer failure rate.

OEB INTERROGATORY #90

Reference:
TSP-03-01 p. 12TSP-01-01 p. 48

Interrogatory:
At the first reference above, Hydro One stated the following:

In response to these risks, Hydro One will invest $594 million over the five year TSP period to replace 95 ABCBs and remove their associated high-pressure air systems (see ISD-SR-01).

At the second reference above, Hydro One stated the following:

System Renewal
Hydro One's TSP reflects the need for continued station renewal investments at a cost of $3.5 billion, or approximately 53% of the total planned capital expenditures over the planning period, to address deteriorated station assets including transformers, circuit breakers, protection, control and telecom equipment. These replacements are expected to approximately maintain the proportion of transformers on the system that are beyond their expected service life at 26%, approximately maintain the proportion of protection systems operating beyond their expected service life at 28% and maintain the number of breakers that are beyond their expected service life at 12%. This includes the replacement of 72% of the air-blast circuit breakers (ABCBs) at a cost of $594M. ABCBs are about 10 times more expensive to maintain and about 4 times less reliable than their equivalent SF6 circuit breakers.

a) Please confirm that this implies an average cost of $6 million per breaker replacement. If not confirmed, please explain.

b) What is the present total annual cost of ABCB maintenance?

c) How many ABCBs receive maintenance attention on average each year?

d) If the planned ABCB replacements are implemented, what are the expected annual O&M cost savings and how will those savings be realized to the benefit of ratepayers? Please provide a detailed explanation of and proportional contribution to savings of each savings source (e.g. workforce reduction and/or re-allocation, fewer contractor hours, reduced consumables, etc.).

Response:

a) Confirmed. On average, the replacement cost per air blast circuit breaker and associated protection, control and ancillary systems is approximately $6 million. Actual costs will vary depending on site specific requirements.

b) Average OM&A expenditure per year across all air blast breakers and associated high pressure air systems is approximately $5.6M.

c) There are various tests with different frequencies that are performed on ABCBs, similar to the maintenance work summarized in Exhibit B-1-1 TSP Section 2.3.1.2 Table 3. Therefore, all ABCB breakers receive some maintenance depending on the frequency of the maintenance task every year. Please refer to Exhibit B-1-1 TSP Section 2.3.1.2 for details on the maintenance of the circuit breaker fleet.

d) Costs associated with maintaining ABCBs are much higher than comparable high voltage oil and SF6 breakers. On average, maintenance for ABCBs and associated high pressure air systems costs $5.6M per year in OM&A while the cost to maintain an SF6 breaker is $5k per year. Thus the replacement of all of the air blast breakers will result in a net reduction of $4.8M per year in transmission maintenance costs.

OEB INTERROGATORY #91

Reference:
TSP-03-01 p. 11-12

Interrogatory:
At the first reference above, Hydro One stated the following:

Circuit Breakers
A circuit breaker is a mechanical switching device that is capable of carrying and interrupting electrical current under normal and abnormal conditions. During abnormal conditions, breakers operate rapidly to interrupt high currents and minimize impact on the rest of the power system. Hydro One's circuit breaker fleet includes 549 units that are currently beyond their ESL. Breakers have been a significant contributor to customer delivery point interruptions over the past 10 years, representing 13% of these equipment caused events. Projections for the number of breakers operating beyond ESL by 2024 and 2029, in the absence of replacements or failures, are 1,088 and 1,766, respectively.

a) Are "customer delivery point interruptions" and "events" used as synonymous terms in this explanation?

b) What percentage of events on Hydro One's system are directly caused by breaker failures?

c) How many customer delivery point interruptions were directly caused by breaker failures over the 10 year period?

Response:
a) In this context, events were used to describe individual delivery point interruptions.

b) Approximately 0.4% of delivery point interruptions were caused by a failure of a breaker. Delivery points can also be interrupted by other outages on breakers that are not the result of complete failure of the breaker.

c) Over the 10 year period 38 delivery point interruptions were attributed to the failure of a breaker.

OEB INTERROGATORY #92

Reference:
TSP-03-01 p. 13

Interrogatory:
At the above noted reference, Hydro One stated the following:

Lines Renewal
Given that a significant portion of Hydro One's transmission lines were built in the 1950s, they will reach the end of their ESL of 90 years in the next two decades. Detailed condition assessments are being conducted for lines exceeding 50 years of age to inform line refurbishment program development. The planned circuit-kilometres of conductor to be replaced in the TSP have been confirmed to be at end of life through condition assessment. While the planned rate of refurbishment does not keep up with the aging lines demographics, risk is being managed by prioritizing line refurbishment investments based on detailed asset condition assessments, which account for the fact that the deterioration rate of transmission line assets depends on location, environmental and system conditions.

a) What proportion of Hydro One transmission lines is presently beyond ESL?

b) What proportion of Hydro One transmission lines will be beyond ESL in 2024 if the lines replacements proposed in this TSP are executed?

c) Given that a significant portion of Hydro One's transmission lines were built in the 1950s, does this mean that the specified "significant portion" of Hydro One's transmission lines are presently 20 or more years younger than ESL? In other words, do those conductors have an expected remaining service life of 20 years or more?

d) Please confirm that transmission conductors installed after 1930 have not yet reached ESL.

e) Were the conductors proposed for replacement in this TSP all installed before 1930?

f) Please explain any discrepancy between the proposed conductor replacement projects and the expected remaining useful service lives of the conductors proposed for replacement based on ESL.

Response:

a) Please refer to Table 17 in Exhibit B-1-1, TSP 2.2, Page 55. 1,389 of 29,107 = 5%

b) Approximately 12%.

c) Yes, transmission lines built in the 1950s are 20 years away from their 90 year ESL.

d) In 2019, ACSR transmission conductors installed after 1930 have yet to reach their ESL of 90 years.

e) No, conductors planned for replacement are driven by condition and not age.

f) No conductor is proposed for replacement based on ESL. All conductors proposed for replacement are based on verified deteriorated condition.

OEB INTERROGATORY #93

Reference:
TSP-03-01 p. 16 TSP-01-01 p. 43

Interrogatory:
At the first reference above, Hydro One stated the following:

Hydro One operates a condition assessment program that focuses on conductors beyond 50 years of age. Condition assessment results indicate that 13% of the conductor fleet is at high risk. Despite a planned increased level of replacements when compared to historical levels, the number of conductors beyond the ESL of 90 years is still increasing. An overhead conductor failure can have severe reliability and safety consequences. If this issue is not addressed in a proactive and timely manner, system and customer reliability as well as safety will be placed at risk. Consequently, an increase in planned replacements – even though it will not completely stop or reverse the trend in line demographics – is required to maintain acceptable fleet condition and performance and to avoid a sudden spike in future investments that would otherwise be required as a result of deferred replacements.

At the second reference above, Hydro One stated the following:

Lines Asset Management
Hydro One's approach to asset management for its transmission line assets is shaped by the nature of the specific line assets and their typical service lives. In particular, transmission conductors have an expected service life of 90 years. When a conductor fails or based on its condition, as confirmed by testing, has been determined to have reached end of life, replacement is the only solution.

a) How common are system events caused by overhead conductor failures? To be more specific, what percentage of Hydro One customer delivery point interruptions are directly caused by spontaneous condition-related conductor failures?

b) How many such events occur each year?

c) Please confirm that the stated percentages and event counts in Hydro One's response to parts a) and b) do not include conductor failures caused by external factors such as tree falls, vehicle contacts, lightning strikes, tornadoes/extreme wind fronts or extreme snow/ice loads that exceed design loads.

d) Please provide a list of the most common conductor-related failure modes experienced by Hydro One (e.g. sagging into objects during hot weather power loads, heavy snow loads or heavy ice loads, blowing into other objects under extreme wind loads, phase to phase contacts under galloping conditions, splice/sleeve failures, dead end/termination compression hardware failures, etc.).

e) Please provide an associated percentage of conductor failures per mode identified in part d).

f) Please distinguish between conductor life and risk of failure versus sleeve (splice) or compression dead end failure.

Response:

a) Approximately 1% of delivery point interruptions are due to conductor failure.

b) There are on average 9 delivery point interruptions per year.

c) The interruptions are related to conductor failure. The mechanism of failure is not readily available.

d) There are two major modes of failure with transmission conductors – loss of tensile strength and loss of ductility. Isolated deficiencies such as surface corrosion bird-caging, strand fraying or splice disconnects can be repaired and are not considered failure modes for the conductor system.

e) Statistics on conductor modes of failure are not readily available.

f) This differentiation is not available. As presented in Exhibit B-1-1, TSP Section 2.2, page 58, conductor caused outages are tracked at the conductor system level as a whole and not down to individual conductor components.

OEB INTERROGATORY #94

Reference:

TSP-01-02 , TSP-03-02

TSP Section 3.2, pp. 10-11, Table 2 and TSP Section 1.2, Attachment 1, p. 2.

Interrogatory:

At the first reference above, Hydro One stated that “The material TSP investments identified through Regional Planning are listed in Table 2…”

At the second reference above, the IESO stated the following:

During the second cycle of regional planning, the Regional Planning Study Team is giving greater consideration to assets reaching end of life. More specifically, they are considering opportunities to “right size” equipment, the potential reliability impact of the longer-term outages required to carry out significant replacement projects, and the potential to optimize the system design as part of the scope of the asset replacement.

a) Please explain why most of the “material TSP investments identified through Regional Planning” are categorized as System Renewal Projects as opposed to System Access and System Service projects.

b) Please confirm that all of the listed SR projects were initially identified as replacement candidates by Hydro One's asset management processes and subsequently brought into the regional planning processes by Hydro One in the context of being projects that would be happening regardless of any regional planning requirements, and that the Regional Planning participants were invited to propose customization or optimization of the identified replacement projects to better address regional planning needs.
   i. If confirmed, is it possible that the regional planning process might have selected a different solution for at least some situations if Hydro One had not offered the replacement projects as already being “fait accompli”?
   ii. If not confirmed, please explain how the SR projects were identified through the Regional Planning processes.

c) Is the IESO involved in determining if Hydro One's assets have reached end of life, or is this solely determined by Hydro One?

d) How are the "end of life" assets introduced into the regional planning process?

e) Is the focus of the regional planning groups limited to providing directional input to Hydro One (e.g.: if you are going to replace a specific asset anyway, consider these system needs when selecting a replacement option)?

f) How is cost sharing between benefiting parties determined when the triggering driver for a regional planning project is end of life asset condition?

g) Does the same answer hold true if the regional planning group determines that it is necessary to upgrade beyond like-for-like replacement, with an associated greater project cost

Response:

a) The regional planning process requires all stakeholders to take a comprehensive look at all planned work in a region and that includes: System Access, System Service and System Renewal projects. With growth in Ontario slow or relatively flat in many areas, relatively few System Access or System Service investments are required. On the other hand, the transmission system in Ontario underwent large development in the 1950 to 1970 period and hence assets placed into service during this period are now reaching end of life. As a result, more System Renewal investments are included in the Regional Plan as compared to System Access or System Service investments.

b) As described in response to part (d) below, Hydro One is accountable to provide all relevant planning information as part of the regional planning process (including end of life information). Hydro One therefore provided the system renewal needs to the regional planning participants. Any potential solutions that were provided by Hydro One were not in the context of being projects that would be happening regardless of any regional planning requirements. The purpose was to ensure that any replacement or refurbishment work was properly assessed within the context of Regional Planning by all regional planning participants.

i/ii. Most of the System Renewal projects have a very straight forward solution of refurbishment or replacement with similar equipment with little or no other options. Any potential solutions that were provided by Hydro One were viewed as input and carefully evaluated by the regional planning participants before developing the recommended plan. The regional planning process is open and transparent; there was no “fait accompli”.

c) Assessment and identification of end of life assets for each type of high voltage equipment requires specialized expertise typically only attained by the facility owner not the system operator. Accordingly, Hydro One solely determines if and when assets have reached end of life and shares the information as an input to the regional planning process.

d) The regional planning process requires Hydro One, LDCs and the IESO to provide relevant planning information to the Regional Planning Study Team, such as: end of life information for major high voltage equipment, load forecast, CDM, DER etc. during the “data gathering” phase of Needs Assessment. Hydro One will provide available information on end of life assets as part of this data gathering for review and assessment by the Study Team.

e) No, the focus of regional planning process is not on providing directional input to Hydro One. The main objective of regional planning is to have a transparent process to promote the cost effective development of electricity infrastructure through coordinated planning on a regional basis. Therefore, both specific asset replacements needs and system needs are carefully considered and the recommendations will mention what and how to address the various specific needs.

f) Cost sharing between benefiting parties is determined consistently based on the OEB’s Transmission System Code (“TSC”).

g) Yes. See response to part (f) above.

OEB INTERROGATORY #95

Reference:
TSP-03-02 p. 13

Interrogatory:
At the above noted reference, Hydro One stated the following:

3.2.4.2 Derivation of Transformer Hazard Functions
This study confirmed that Hydro One's pacing approach to the replacement of transformers is appropriate.

3.2.4.3 Derivation of Circuit Breaker Hazard Function
This study was performed by EPRI and describes EPRI's efforts to (i) model and develop circuit breaker removal rates from historical replacement records and (ii) apply them to forecast the number of circuit breakers expected to require replacement based on past practices. EPRI has developed a methodology using advanced statistical techniques for analyzing circuit breaker historical removals and applied it to the Hydro One's circuit breaker fleet. Using Hydro One's circuit breaker retirement data, EPRI modeled Hydro One's circuit breaker removals and has forecast probable future removal rates. The study confirmed that Hydro One is replacing younger circuit breakers at a rate expected from the statistical model.

a) Please confirm that EPRI actually derived a transformer "removal rate" function, utilizing the uncategorized transformer removal data provided by Hydro One.

b) Please confirm that EPRI actually derived a breaker "removal rate" function, utilizing the uncategorized breaker removal data provided by Hydro One.

c) Please explain how the conclusions in 3.2.4.2 and 3.2.4.3 can be considered as accurate given that they are based on uncategorized asset removal data.

Response:
a) Confirmed, it is a removal rate function. However, the transformer removal data provided by Hydro One to EPRI was categorized by transformer style, voltage class,

age, removal date and fleet size for each voltage class of transformers. For more detailed information of input data, please refer to ERPRI repot.

b) Confirmed, it is a removal rate function. However, the breaker removal data provided by Hydro One to EPRI was categorized by breaker style, voltage class, age, removal date and fleet size for each voltage class of breakers. For more detailed information of input data, please refer to EPRI repot.

c) As stated as above, the removal data provided by Hydro One to EPRI are categorized. EPRI used a systematic and scientific approach in analyzing these data, which provides confidence in their analysis.

OEB INTERROGATORY #96

Reference:
TSP-03-02 p. 25

Interrogatory:
At the above noted reference, Hydro One stated the following:

Hydro One's average frequency of sustained delivering point interruptions (T-SAIFI-S) performance over the past five years was 0.63 per delivery point, and the performance trend is indicating an increase in the average number of sustained interruptions per delivery point.

a) How steep is the performance degradation trend mentioned above?

b) Is the performance degradation trend slope greater than 1 standard deviation from the mean?

c) Is this problem sufficiently urgent to justify a 40% capital spending increase?

Response:
a) The trend is 0.053 increase year over year during the 5 year period

b) The slope in this context is the rate of change year over year. The mean refers to the 5 year average and standard deviation refers to the variability of the 5 year values and can be calculated to be 0.63 and 0.14 respectively.

   The slope is numerically smaller than the mean and standard deviation.

c) See Response to OEB Interrogatory #002, Exhibit I, Tab 1, Schedule 96, part a)

OEB INTERROGATORY #97

Reference:
TSP-03-02 p. 6-7

Interrogatory:
At the above noted reference, Hydro One discussed system renewal investments.

a) Regarding the overspend in 2015 and 2016, were the overspent amounts within Hydro One's expected +/- cost range for this project?

b) Did the "increased spending on emergency replacements and spare transformer purchases" in 2015 lower spending requirements in later years?

c) If not, why not?

d) Please explain how "the complexity of the required environmental assessments and public consultation" resulted in a $15 million reduction in spending? Did this underspend fall within Hydro One's expected +/- cost range for this project?

Response:
a) The overspend noted in 2015 and 2016 reflects System Renewal expenditures on an annual basis relative to the plan. While the projects noted in Exhibit B-1-1 TSP Section 3.3, pages 6-7, contributed to overspend within those calendar years, Hydro One, in the preparation of estimates, establishes a range for the overall project total and not individual calendar years. Due to the multi-year nature of projects annual expenditures may be impacted by factors such as outage availability, procurement timing, or external approvals. These factors may result in either advancing or deferring expenditures as system constraints and resources permit, which may result in an annual variance to planned spending, but still maintain total project expenditures within expected cost ranges. Monitoring and tracking of in year expenditures and variance to plan is detailed in Exhibit B-1-1 TSP Section 2.1.9.2 "Monitoring & Control", and Exhibit B-1-1 TSP Section 2.1.9.3 "Redirection of Funds".

b) No.

c) Increased spending requirements on emergency replacement and spare transformer purchases would not lower spending requirements in future years, as failed units may not have been scheduled for planned replacement in future years. In circumstances where the failed unit was already planned for replacement, Hydro One, through the continuous asset risk assessment process detailed in Exhibit B-1-1 TSP Section 2.1 would prioritize and optimize the overall transmission capital portfolio, to ensure the proper mix of investments to manage costs, asset/system operational risks, customer needs and preferences, customer rate impacts, and achieve the company's business objectives and outcomes.

d) More time was required for the environmental assessment and public consultations related to an underground cable replacement, resulting in the project being delayed and costs deferred to future years.

OEB INTERROGATORY #98

Reference:
TSP-03-03 ISD-GP-01 p. 5

Interrogatory:
At the above noted reference, Hydro One stated the following:

In Hydro One's previous OEB rate filing applications, this ISOC investment was planned for a dual primary control and monitoring configuration, but to realize better operating synergies, it was decided that a single primary configuration will deliver more benefits. The updated plan involves making the ISOC Hydro One's primary control centre once it is fully in-service so that the deficiencies at the OGCC will be remedied without impact on real-time operations. The OGCC will then be re-designated as the backup centre. The existing BUCC will then be decommissioned. Incremental costs associated with this updated plan will only be from employee relocation considerations. This amount is forecast to be between $1 million to $3 million. The relocation cost will be budgeted as a one-time OM&A charge, and it is not included in this Investment Summary Document costing.

a) When was the current Ontario Grid Control Centre (OGCC) constructed?

b) What was the actual all-in cost of the OGCC when constructed?

c) What is the total remaining undepreciated OGCC rate base?

d) What uncertainties are driving the $1 million to $3 million OM&A charge cost range and what is the basis for this charge?

Response:
a) Construction was completed in September 2004.

b) The cost was $118M total and unallocated, which includes OM&A costs which are not depreciated.

c) Of the initial $118M investment, the OGCC is almost fully depreciated with the total remaining undepreciated rate base equal to $6.7 million as of Dec 31, 2018. There have been investments approved as part of prior rate applications since the original investment. These have a remaining net depreciated value of $94.6M. The $94.6M is mainly comprised of technology assets that are located both at the OGCC and the BUCC. These technology assets are refreshed based on regular IT lifecycles that will continue and be leveraged into the new control centre as well.

d) As referenced in ISD-GP-01 page 5 line 7: “Incremental costs associated with this updated plan will only be from employee relocation considerations. This amount is forecast to be between $1 million to $3 million” depending on how many eligible staff will relocate rather than choose to commute to the new location. The relocation fees are based on Hydro One’s collective bargaining agreements to provide relocations expense. As of now, Hydro One cannot predict who will exercise the relocation option.

OEB INTERROGATORY #99

Reference:

TSP-03-03 ISD-GP-01 p. 17

Interrogatory:

At the above noted reference, Hydro One stated the following:

The exclusion of the SOC [security operations centre] was rejected, because it fails to maximize financial performance through synergistic lines of business occupancy and maximize use of shared critical infrastructure. Bringing SOC services to the ISOC will reduce security monitoring service OM&A cost by approximately $0.6M on an annual basis. This SOC exclusion also fails to leverage operational effectiveness synergies for operational response to security threats, both physical and cyber. By co-locating physical security monitoring (i.e. SOC) with the other lines of business, opportunities for collaboration on physical risk mitigation will be optimized.

a) Does the proposed arrangement increase the probability of common mode failure of multiple lines of Hydro One business responsibility due to lack of space diversity? If no, please explain why not.

b) Please explain the meaning of the phrase "it fails to maximize financial performance through synergistic lines of business occupancy".

Response:

a) Hydro One has designed the building to meet physical security requirements of a Tier III facility. The “Tier III” designation is set by the Uptime Institute for data centre infrastructure. A Tier III data centre facility requires no shutdowns for equipment replacement and maintenance by including redundant power and cooling equipment and redundant delivery paths into the design. Uninterruptable Power Supplies, Computer Room Air Conditioning units, and standby generators are some of the components providing increased margin of safety to protect against disruptions.” As a result, *Alternative 4: Initiate Build of the Integrated System Operations Centre (“ISOC”) (Recommended)* does not increase the probability of common mode of failure of multiple lines of business due to the shared integrated data centre and support infrastructures at the preferred site. The ISOC will be built to be a hardened facility. Additionally, the data centre will be built to meet Tier III facility requirements. Therefore, reducing the probability of a common mode failure is inherent in the design of a facility of this nature.

Please see ISD-GP-01, page 6, lines 17 to 21 for a description of a hardened facility. Please see “Additional Design Criteria” which can be found in ISD-GP-01, page 10 line 15 to page 11 line 5, including footnote 3 on page 11.

b) This phrase refers to the fact that under *Alternative 2*, Hydro One will save money by avoiding duplicative infrastructure. This is described in ISD-GP-01, page 11, lines 7 to 24, as follows:

> *“The integrated strategy behind the ISOC facility reduces third-party costs, optimizing financial performance by also eliminating the need for additional sites and facilities that would otherwise be required. By building one centralized site to house all stakeholders, the following synergies will be realized: negating the need for multiple designs, development, sites, facilities (buildings), critical support infrastructure, future maintenance maximizing capital investment, limiting overall rate impacts.”* (Lines 7-14).

Build configuration of *Alternative 2: Build a modified version of ISOC on the preferred Orillia Site* contemplates removing the Security Operations Center (“SOC”) from the preferred Orillia site. Removing the SOC from the Orillia site in Alternative 2 would result in third-party costs and costs associated with additional sites and facilities, which would prevent the synergies associated with the ISOC strategy from being realized.

> *“All proposed tenants in the recommended Alternative 4, including various lines of business departments such as the System Operating Division, Hydro One Telecom, Security Operations, and Power System IT, among others, require costly critical support infrastructure and IT investment to meet an availability target (99.95% uptime) commensurate with the criticality of the systems and functions they support. These requirements are prescribed by Hydro One internal reliability standards PP-66400-002-R1 and guided by industry best practices (Uptime Institute Availability -*

Tier levels, as outlined in Internal Power System Monitoring and Control Reliability Requirements PP-66400-002-R1 sections 4.1.2 and 4.1.8). With the current ISOC strategy, the critical support infrastructure is shared by the tenants and represents an incremental cost to achieve it rather than replicating the installations that would be required to support several sites across Ontario." (Lines 14 to 24).

OEB INTERROGATORY #100

Reference:
TSP-03-03 ISD-GP-02 p. 2

Interrogatory:
At the above noted reference, Hydro One stated the following:

2. Telecom circuits have migrated from older point to point connections to modern IP based routable circuits. These newer circuits do not have the same geographic limitations.

a) Does migration from “point to point” to “IP based routable circuits” increase the Integrated System Operating Centre (ISOC) exposure to malicious software attacks?
   i. If yes, please quantify the increased exposure.
   ii. If no, explain why not.

Response:
a) There is a low amount of risk introduced when using IP routable circuits over dedicated point to point connections. The risk is managed with appropriate security practices.

   Hydro One’s IP based routable circuits are set aside solely for Hydro One communication and have no internet connectivity. All of Hydro One’s information transmitted over these IP routable circuits are encrypted, and equipment on both sides of the Hydro One IP routable circuit only expose what is necessary to transmit/receive information over this encrypted channel. In addition, Hydro One operating centers are also equipped with intrusion detection systems (IDS) and intrusion prevention systems (IPS) to monitor/protect the system from any incoming traffic with malicious software attacks.

Witness: Donna Jablonsky

OEB INTERROGATORY #101

Reference:

TSP-03-03 ISD-SR-02 p. 1

Interrogatory:

a) The priority of SR-02 Station Reinvestment Projects, as well as many other projects identified in this filing, is identified as "Medium". Will Hydro One have any outstanding "High" priority projects at the end of the test period?
   i. If yes, please explain why Hydro One is proposing to execute Medium priority projects prior to completing all outstanding High priority projects.
   ii. If yes, does this indicate need for refinement/recalibration of Hydro One's project prioritization methodology, mischaracterization of project priorities, inability to deliver all High priority projects during the test period, or something else? Please explain.

Response:

a) Hydro One will have projects identified as “High” priority that will continue execution beyond the test period. The projects and programs identified within TSP Section 3.3 vary in execution timeline as articulated within the respective Investment Summary Documents. The relative staging of investments is complex and based on a number of considerations. Non-discretionary investments, typically those identified as System Access and System Service, have timelines driven by factors external to Hydro One, as a result certain high priority investments may not commence until the end the planning period.

   The Investment Planning Process, detailed in TSP Section 2.1 developed the plan that supports this Transmission System Plan. Through this process, proposed investments are prioritized and optimized to manage costs, asset/system operational risks, customer needs and preferences, customer rate impacts, and achieve the company’s business objectives and outcomes over the 2020-2024 planning period. The Transmission System Plan filed as part of this proceeding details the capital investment required over the five-year planning period, therefore in the prioritization and optimization of investments to achieve the outcomes listed above, it would be expected that some investments will be in-serviced after the three-year Test period.

Witness: Robert Reinmuller

OEB INTERROGATORY #102

Reference:
TSP-03-03 ISD-SR-02 p. 7

Interrogatory:
At the above noted reference, Hydro One stated the following:

C. EXPENDITURE PLAN
As discussed above, this investment is needed to replace various bulk power and load supply station assets that have reached their expected service life ("ESL") and are in deteriorated condition, which may lead to unexpected failures. Hydro One planned this investment to achieve completion as effectively and efficiently as possible.

a) Are any of the stations in this program being rebuilt because major components have reached ESL?

Response:
a) No. Investments in this program, ISD SR-02, have been identified because major components have reached end-of-life (EOL).

Witness: Robert Reinmuller

OEB INTERROGATORY #103

Issue from Draft List:
[Issue Group]

Reference:
TSP-03-03 ISD-SR-02 p. 9
Table 2

Interrogatory:
a) Please indicate which of the listed station projects are potentially subject to increased costs due to each of following factors, and quantify the expected project cost increase due to each factor:
    i. NERC/NPCC requirements;
    ii. Environmental work;
    iii. In situ replacement.

Response:
a) Please see Table 1 below for the list of projects that are subject to NERC/NPCC requirements, environmental work, or whether it will be an in situ replacement. The total costs or each project presented in the ISD are inclusive of the work required to meet the necessary compliance obligations and achieve the described scope. As detailed in the ISD, multiple factors affect the overall total cost of the project, including complexity, geography, location, and compliance requirements. It cannot be generally stated that in situ replacement will result in increased project cost, but due to design complexity, staging requirements, customer impact, there may be impact on overall project timeline. Depending on factors such as station arrangement, geography, real estate availability, an in situ replacement may be the only viable alternative. The work required to meet specific compliance obligations or proceed with an in situ replacement is not itemized in an incremental manner and is included within the overall project cost.

Table 1: Project Classification

Project	NERC / NPCC Requirements	Environmental Work	In Situ Replacement
Elgin TS	[redacted]	Y	N
Sheppard TS	[redacted]	Y	N
Pine Portage SS	[redacted]	N	Y
Hanmer TS	[redacted]	Y	N
Gage TS	[redacted]	Y	N
Kenilworth TS	[redacted]	Y	N
Runnymede TS	[redacted]	Y	N
Belleville TS	[redacted]	Y	N
Martindale TS	[redacted]	Y	N
Carlton TS	[redacted]	Y	N
Port Colborne TS	[redacted]	Y	N
Slater TS	[redacted]	N	Y
Wonderland TS	[redacted]	Y	N
Lambton TS	[redacted]	Y	N
Glendale TS	[redacted]	Y	N
Fairbank TS	[redacted]	Y	Y
Arnprior TS	[redacted]	Y	N
Hanover TS	[redacted]	Y	N
Kent TS	[redacted]	Y	N
St. Andrews TS	[redacted]	Y	N
Wawa TS	[redacted]	Y	N

OEB INTERROGATORY #104

Reference:

TSP-03-03I SD-SR-02 P. 11-12

Interrogatory:

At the above noted reference, Hydro One stated the following:

Alternative 2: Planned Replacement of Components (Unbundled) involves replacing individual station components in high risk and deteriorated condition on a sequential basis as each component reaches its end of useful service life. This alternative is viable only when single components at a transmission station are deteriorated. Unlike reactive replacements, planned replacements have the advantage of minimizing system and equipment outages through coordinated outage plans. However, this alternative is not efficient when multiple components at a transmission station are in deteriorated condition or operational concerns exist with respect to these components. Since a component based planned replacement strategy would only replace assets as they come to end of life, Hydro One would not realize any efficiency during execution of the design, construction, and commissioning stages of the work that a station-centric, bundled replacement strategy offers. Furthermore, this alternative does not offer any opportunities to reconfigure the physical or electrical layout of the station in order to minimize future maintenance requirements or to eliminate any existing operational concerns.

a) Please quantify the total loss of useful service life by asset for all assets being retired prior to end of life in each of the cited station projects.

b) Please quantify (in monetary terms) the offsetting efficiency gain used by Hydro One to justify early retirement of the assets being retired in each of these projects that will not have reached end of life when it is retired.

Response:

a) Hydro One only bundles assets that have reached end-of-life ("EOL") and their associated systems which would require replacement within a 3 year time frame, the most an asset could be advanced for replacement is 2 years. The majority of station assets have life cycles ranging from 20-60 years so 2 years represents a very small percentage of the overall asset lifecycle. Investments proposed under SR-02 are stations where a significant majority of assets have reached EOL. The term "*useful service life*" is qualitative and is used to describe the condition and expected remaining performance of an asset. Quantifying "*loss of useful service life*" would require the finite and unique determination of when an asset will reach end-of-life. Using an asset's expected service life ("ESL") in this assessment is not reflective of Hydro One's condition based replacement criteria as ESL is a fleet level quantitative measure, as detailed in TSP Section 2.2. Hydro One's planning philosophy seeks to maximize asset life by balancing prudent replacement before failure and increased failure risk with potentially higher cost and system and customer impact.

Hydro One continually maintains and monitors the condition, performance and other factors of its assets as detailed in TSP Section 2.0. This information continually informs the development and refinement of candidate investments through the asset risk assessment ("ARA") process to ensure expenditures address asset needs and are optimized and prioritized as detailed in TSP Section 2.1.

The advantages of work bundling are significant considering construction mobilization and demobilization, efficiencies in planning, reduced maintenance costs associated with asset renewal, engineering, equipment commissioning, reduced outages which result in a reduction in customer interruptions. In addition the resulting investment is fully upgraded to current design standards and technology for improved safety, environment and reliability performance. This planning and execution methodology is consistent with the approach detailed within Hydro One's previous application, proceeding EB-2016-0160, with regards to integrated investment.

b) See response to part a).

OEB INTERROGATORY #105

Reference:

TSP-03-03 ISD-SR-03 p. 2

Interrogatory:

At the above noted reference, Hydro One stated the following:

The Project pacing has been influenced by bulk transformer fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental and safety concerns, as described below. Based on Hydro One's overall transformer demographic profile, it is forecasted that an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

a) Is exceeding ESL the primary driver or an important factor driving any of the transformer replacements identified in this program?
   i. If yes, please identify those replacements.
   ii. If no, please identify the primary driver for each proposed replacement.

Response:

a) Exceeding ESL is not the primary driver for the transformer replacements identified in this program. As detailed in TSP Section 2.2, the primary driver for asset replacement decisions is reaching end of life ("EOL"). The primary driver for all transformers in this program is that they have reached EOL.

Witness: Robert Reinmuller

OEB INTERROGATORY #106

Reference:
TSP-03-03 ISD-SR-04 p. 2

Interrogatory:
At the above noted reference, Hydro One stated the following:

The Projects pacing has been influenced by the assessment of equipment condition and in consideration of operational effectiveness, customer preferences, and safety concerns. Based on Hydro One's bulk station breaker demographic profile, it is forecasted an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Projects.

a) Please quantify the increased system reliability risk that would be associated with not making the proposed investments during the test period.

Response:
a) SR-04: Bulk Station Switchgear and Ancillary Equipment Replacement will address assets which, if failure were to occur, could partially or entirely constrain generation resources and would lessen the reliability of bulk power flows to load centres, including Northern Ontario and the Greater Toronto Area. Should these asset replacements be deferred, it is estimated that approximately 39,000 MW of circuit capacity power flow could be at risk, representing approximately 12% of system circuit capacity power flow. The impact of bulk station equipment failures could be far reaching if multiple assets fail unexpectedly and impact capacity transfers between large generators and load or tie line limits. These failures could become reportable events in NPCC. Accepting this risk would jeopardize system adequacy and customer load.

OEB INTERROGATORY #107

Reference:

TSP-03-03 ISD-SR-04 p. 7 & 9
Figure 2 & Table 9

Interrogatory:

a) The demographic trend in Figure 2 appears to indicate a relatively slow increase in the cumulative total number of breakers operating beyond ESL if no additional breakers are replaced during the test period. Please explain the pacing of the investments shown in Table 1 in the context of the demographic trend shown in Figure 2 above.

b) How many forecast years are included in the "Forecast 2025+" column in Table 1?

c) Do the values listed in the "Forecast 2025+" column in Table 1 represent the average annual spend or cumulative total spend for the Forecast period? Please explain.

d) How many historical years are included in Table 1's "Prev. Years" column?

e) Do the values listed in the "Prev. Years" column represent the average annual spend or the cumulative total spend of the historical period? Please explain.

f) Do the assumptions noted in responses b) through e) apply to all ISDs included in this filing?

Response:

a) Hydro One carries out an Investment Planning Process, detailed in TSP Section 2.1, to identify, prioritize and optimize investments to manage asset/system operational risks. Included as part of this process, Hydro One performs a continuous asset risk assessment ("ARA") process to determine individual asset needs. Detailed in TSP Section 2.2, the primary driver for asset replacement is reaching end-of-life ("EOL"). Therefore while assets may be operating beyond ESL, they may not be EOL. Conversely, an asset may not be beyond ESL when it is deemed to have reached EOL. The pacing of investments identified in this program reflect the overall prioritization and optimization resulting from the Investment Planning Process.

b) The number of forecast years in the "Forecast 2025+" column in Table 1 includes up to the *In-Service Date* of the ISD, which for SR-04 is 2027.

c) The values listed in the "Forecast 2025+" column in Table 1 represent the cumulative total spend for 2025 and beyond for the investments identified within the ISD.

d) The number of historical years included in Table 1’s "Prev. Years" column include from the Start Date of the ISD, which for SR-04 is 2017.

e) The values listed in the "Prev. Years" column represent the cumulative total spend of the historical period for the investments identified in the ISD.

f) The assumptions noted in responses b) through e) apply to all ISDs included in this filing that are not identified as “Ongoing Programs”.

OEB INTERROGATORY #108

Issue from Draft List:

[Issue Group]

Reference:

TSP-03-03, ISD-SR-04

Interrogatory:

a) Please indicate which of the listed projects in Table 2 are potentially subject to increased costs due to each of following factors, and quantify the expected project cost increase due to each factor:
   i. Ministry of the Environment, Conservation and Parks requirements;
   ii. NERC requirements;
   iii. NPCC Requirements;

b) Which projects are new location installations and which are in-situ installations?

Response:

a) Please see Table 1 below for the list of projects that are subject to MOECP and NPCC/NERC requirements. The total costs or each project presented in the ISD are inclusive of the work required to meet the necessary compliance obligations and achieve the described scope. The work required to meet specific compliance obligations is not itemized in an incremental manner and is included within the overall project cost. As detailed in the ISD, multiple factors affect the overall total cost of the project, including complexity, geography, location, and compliance requirements.

Table 1: Classification of Projects

Project	MOECP Requirements	NERC Requirements	NPCC Requirements	Switchgear In Situ
Trafalgar TS	N	[redacted]	[redacted]	Y
Claireville TS	N	[redacted]	[redacted]	Y
Rabbit Lake SS	N	[redacted]	[redacted]	Y
Milton SS	N	[redacted]	[redacted]	Y
Marathon TS	N	[redacted]	[redacted]	Y
Mackenzie TS	N	[redacted]	[redacted]	N
Merivale TS	N	[redacted]	[redacted]	Y
St.Lawrence TS	N	[redacted]	[redacted]	Y
Kenora TS	N	[redacted]	[redacted]	Y
Mississagi TS	N	[redacted]	[redacted]	Y
Lakehead TS	N	[redacted]	[redacted]	Y

b) See response in part a).

OEB INTERROGATORY #109

Reference:
TSP-03-03, ISD-SR-05

Interrogatory:
At the above noted reference, Hydro One stated the following:

The Project pacing has been influenced by load supply transformer fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental and safety concerns, as described below. Based on Hydro One's overall transformer demographic profile, it is forecasted that an increasing number of units will age beyond Expected Service Life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases supply reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

a) Please quantify the potential impact upon supply reliability if the transformers (and associated equipment) proposed for replacement in this program are not replaced during the test period.

Response:
a) SR-05: Load Station Transformer Replacements will address assets which, if failure were to occur, could partially or entirely interrupt supply to load customers, including those in the Niagara, Ottawa, and Greater Toronto and Hamilton Area. Should these asset replacements be deferred, it is estimated that approximately 1,600 MW of load could be at risk, representing approximately 8% of average system load. It would be irresponsible of Hydro One to accept this risk and jeopardize the system adequacy and customer load, while accepting the unintended reliability, environmental and safety consequences of unplanned failures.

OEB INTERROGATORY #110

Reference:

TSP-03-03, ISD-SR-05

Interrogatory:

a) Please identify which of the listed transformer replacement projects in Table 3 are potentially subject to increased costs due to each of following factors, and quantify the expected project cost increase due to each factor:
   i. Ministry of the Environment, Conservation and Parks requirements;
   ii. PCB compliance requirements;

b) Which transformer replacement projects in Table 3 are new location installations and which are in-situ installations?

Response:

a) Please see Table 1 below for the list of projects that are subject to MOECP and PCB compliance. The total costs or each project presented in the ISD are inclusive of the work required to meet the necessary compliance obligations and achieve the described scope. The work required to meet specific compliance obligations is not itemized in an incremental manner and is included within the overall project cost. As detailed in the ISD, multiple factors affect the overall total cost of the project, including complexity, geography, location, and compliance requirements.

Table 1: Classification of Projects

Project	MOECP Requirements	PCB Compliance	Transformer(s) In-Situ
Hawthorne TS	Y	Y	Y
Strachan TS	Y	N	Y
Stanley TS	Y	Y	N
Minden TS	Y	Y	N
Main TS	Y	N	N
King Edward TS	N	N	Y
Hanlon TS	Y	N	N
Wingham TS	Y	Y	Y
Kingsville TS	Y	Y	N

Project	MOECP Requirements	PCB Compliance	Transformer(s) In-Situ
Thorold TS	Y	N	N
Stratford TS	Y	N	Y
Cedar TS	Y	N	N
Crowland TS	Y	Y	N
Murray TS	Y	N	N
Orangeville TS	Y	Y	N
Bridgman TS	Y	N	N
Parry Sound TS	Y	N	N
Moose Lake TS	Y	N	N
Lauzon TS	Y	Y	Y
Port Hope TS	N	Y	Y
Longueuil TS	N	N	Y
Clarke TS	Y	N	N
Preston TS	Y	N	Y
Birmingham TS	Y	Y	N
Newton TS	Y	N	N
Palermo TS	Y	Y	N
Gage TS	Y	N	N
Bermondsey TS	Y	Y	Y
Leslie TS	Y	Y	N
Wilson TS	Y	Y	N
Charles TS	Y	Y	Y
Duplex TS	Y	Y	Y
Woodbridge TS	Y	N	N
Bathurst TS	Y	N	Y
Strachan TS	Y	N	Y
Wallace TS	N	N	Y
Bilberry Creek TS	N	N	Y
Russell TS	N	N	Y
Elliot Lake TS	Y	N	N
Fairchild TS	Y	Y	N

b) See response to part a).

Witness: Robert Reinmuller

OEB INTERROGATORY #111

Reference:
TSP-03-03, ISD-SR-06

Interrogatory:
At the above noted reference, Hydro One stated the following:

The Project pacing has been influenced by the assessment of equipment condition and in consideration of operational effectiveness, customer preferences, and safety concerns. Based on Hydro One's load supply station breaker demographic profile, it is forecasted an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

a) Please quantify the potential impact upon system reliability if the load station and ancillary equipment proposed for replacement in this program are not replaced during the test period.

Response:
a) SR-06: Load Station Switchgear and Ancillary Equipment Replacement will address assets which, if failure were to occur, could partially or entirely interrupt supply to load customers, including those in the Ottawa, and Greater Toronto and Hamilton Area. Should these asset replacements be deferred, it is estimated that approximately 3,000 MW of load could be at risk, representing approximately 15% of average system load. It would be irresponsible of Hydro One to accept this risk and jeopardize the system adequacy and customer load, while accepting the unintended reliability, environmental and safety consequences of unplanned failures.

Witness: Robert Reinmuller, Bruno Jesus

OEB INTERROGATORY #112

Issue from Draft List:
[Issue Group]

Reference:
TSP-03-03, ISD-SR-06

Interrogatory:

a) Please identify which of the listed projects in Table 2 are potentially subject to increased costs due to each of following factors, and quantify the expected project cost increase due to each factor:
   i. Ministry of the Environment, Conservation and Parks requirements;
   ii. NERC requirements;
   iii. NPCC Requirements;
   iv. PCB compliance requirements;

b) Which projects are new location installations, and which are in-situ installations?

Response:

a) Please see Table 1 below for the list of projects that are subject to NERC/NPCC requirements, MOECP requirements, or PCB compliance. The total costs or each project presented in the ISD are inclusive of the work required to meet the necessary compliance obligations and achieve the described scope. As detailed in the ISD, multiple factors affect the overall total cost of the project, including complexity, geography, location, and compliance requirements. The work required to meet specific compliance obligations is not itemized in an incremental manner and is included within the overall project cost.

Table 1: Project Classification

Project	MOECP Requirements	NERC Req.	NPCC Req.	PCB Compliance	Switchgear In Situ
Leaside TS	N	[redacted]	[redacted]	Y	N
SACE Breakers	N	[redacted]	[redacted]	N	Y
Finch TS	N	[redacted]	[redacted]	Y	N
Rexdale TS	Y	[redacted]	[redacted]	N	Y
Bridgman TS	N	[redacted]	[redacted]	N	N
Kirkland Lake TS	N	[redacted]	[redacted]	N	N
Campbell TS	N	[redacted]	[redacted]	N	N
Norfolk TS	N	[redacted]	[redacted]	Y	Y
Bunting TS	N	[redacted]	[redacted]	N	N
Owen Sound TS	N	[redacted]	[redacted]	Y	N
Dundas TS	N	[redacted]	[redacted]	Y	N
Lake TS	N	[redacted]	[redacted]	Y	N
Burlington TS	N	[redacted]	[redacted]	Y	N
Mohawk TS	N	[redacted]	[redacted]	N	N
Vansickle TS	N	[redacted]	[redacted]	N	N
Cherrywood TS	Y	[redacted]	[redacted]	N	Y
Port Arthur TS #1	N	[redacted]	[redacted]	N	N
Muskoka TS	N	[redacted]	[redacted]	N	N
Pleasant TS	N	[redacted]	[redacted]	Y	Y

b) See response to part a).

OEB INTERROGATORY #113

Reference:
TSP-03-03, ISD-SR-13

Interrogatory:
At the first reference above, Hydro One stated the following:

Hydro One has been phasing out ADSS fibre optic cables from its asset base due to high risks to reliability and safety. The remaining sections of ADSS fibre cable have deteriorated significantly over the recent years. Excessive premature wear and tear has compromised the asset and hence Hydro One's ability to operate the transmission system reliably. In order to maintain the reliability of the transmission system, there is a need to replace remaining sections of Hydro One owned ADSS fibre optic cable.

At the second reference above, Hydro One stated the following:

The Expected Service Life (ESL) of fibre optic cable is based on the type of cable. The manufacturers' recommended ESL for OPGW is 40 years and 25 years for ADSS. Historical performance shows that the mechanical aspects of the fibre cable can prematurely reduce the cable's life span. In the case of ADSS cables, unusual mechanical stresses have resulted in high rate of premature failures before its ESL expired. ESL is now lowered to 15 years and it is used to trigger the asset condition assessment in the replacement decision making process.

a) What is causing the premature wear and tear of the ADSS fibre cable? Was the ADSS incorrectly specified, was it incorrectly designed and installed, were there manufacturing defects or type faults, or other? Please list all reasons that apply and explain.

b) What is the reason for the unusual mechanical stresses?

c) Will Hydro One have any remaining ADSS when this program has been completed?

Response:

a) As discussed in ISD-SR-13 p. 2 lines 21-25, premature wear and tear on ADSS fibre cable has been as a result of excessive and uncontrolled cable vibrations. The ADSS cables were correctly specified and had no known manufacturing defects or faults; however Hydro One had limited experience in installation and maintenance of these new types of fibre cables at the time they were introduced to the system. This limited experience combined with some design work contracted out (due to limited internal expertise), led to ADSS cable performance not being as expected.

b) At the time ADSS cable was first installed by Hydro One, there was limited research available to better understand the design principles, maintenance requirements and operational risk related to ADSS cables. Historical performance have shown that a combination of these reasons have contributed to unusual mechanical stresses as well as some of the early ADSS cable failures.

c) Yes. Hydro One will have small sections (approx. 3km) of ADSS left that will be phased out through the shieldwire replacement program or line refurbishment projects.

OEB INTERROGATORY #114

Reference:
TSP-03-03, ISD-SR-19

Interrogatory:
At the first reference above, Hydro One stated the following:

A. OVERVIEW
This set of Transmission Line Refurbishment Projects involve the replacement of all End-Of-Life ("EOL") components along all or part of a line section. These projects are driven by the need to replace major transmission line components, verified to be at EOL by condition assessment, including Aluminum Conductor Steel Reinforced ("ACSR") conductor, obsolete copper conductor, or deteriorated structures in high risk condition.

At the second reference above, Hydro One stated the following:

A. OVERVIEW
Near End-of-Life Transmission Line Refurbishment Projects (the "Projects") involves the proactive replacement of the Aluminum Conductor Steel Reinforced ("ACSR") conductors that are confirmed, through condition assessments, to be in a deteriorated condition and approaching End-Of-Life ("EOL"). The near EOL conductors are assets whose condition is expected to be in a state requiring removal from service in the near future. Over the test period, there is large population of overhead ACSR conductor that will reach or exceed their Expected Service Life ("ESL") and therefore the probability of their failure is increasing as a result of their aggregate increase in deteriorated condition.

a) Is conductor condition the primary driver for all of the projects included in both the SR-19 and SR-20 programs?
   i. If no, please identify all projects in these programs with a different primary driver (other than conductor condition), list the primary driver associated for each project, and explain why these projects are included in this program.

b) Please confirm that all conductors and/or all structures throughout the length of the identified segments have been verified to be at end of life.

i. If not confirmed, please identify what percentage of the conductor and/or percentage of structures in the identified segments have been confirmed to be at end of life.

Response:

a) Conductor condition is the primary driver for all projects in SR-19 and SR-20, except:

ISD	Project	Reason for inclusion
SR-19	N21W/N22W, Sarnia Scott TS X Buchanan TS, Tx Str. Refurb.	This project is driven by the need to refurbish the lattice steel structures, which were built to an under-designed specification. Bundled in this undertaking is replacement of verified end-of-life shieldwire and u-bolts. This project does not replace the conductor, but replaces and refurbishes a majority of the other components making up a transmission line and is therefore included into SR-19.

b) The line sections making up the projects listed in SR-19 and SR-20 have been verified through condition assessment to contain End-Of-Life (“EOL”) or near EOL assets respectively. These projects will be planned, designed and executed to only replace EOL or near EOL assets.

OEB INTERROGATORY #115

Reference:
TSP-03-03, ISD-SR-19

Interrogatory:
At the first reference above, Hydro One stated the following:

Hydro One has evaluated various alternatives for these Projects, as described below, and concluded that replacing the EOL deteriorated ACSR, obsolete copper conductors, or refurbishing deteriorated structures is the most cost effective and efficient undertaking for sustaining these assets.

At the second reference above, Hydro One stated the following:

Presently, the Hydro One overhead transmission system has 3,680 km of conductor known to be in high risk condition, as verified empirically through condition assessment.

a) What is the predicted conductor-driven probability of failure of each of the lines with ACSR conductor in this program if those lines are not rebuilt during the test period?

b) Please clarify whether there are 3,680 km of conductor or 3,680 circuit-km known to be in high risk condition.

c) Of the 3,680 km of conductor "known to be in high risk condition", what is the probability of conductor system failure per km during the test period?
   i. What is the basis for the claimed value?

d) Please describe the condition assessment analysis that was undertaken to determine the high risk condition of the identified conductors.

e) Is the condition of the sleeves and dead ends in the high risk sections of more concern than the condition of the conductor between the sleeves and dead ends?

Response:

a) The probability of failure of each line is not available. All line sections making up the projects listed in SR-19 have been verified through condition assessment to contain End-Of-Life ("EOL") assets, which can no longer safely and reliably perform their designed function.

b) 3,680 circuit-km are known to be in high risk condition.

c) See a)

d) As per Exhibit B-1-1, TSP Section 2.3, the majority of conductor condition was established through conductor sample removal and laboratory testing. More recently Hydro One has used the Kinectrics LineVue tool, which is able to travel along energized and non-energized conductor spans to measure the remaining cross-sectional area of the steel core wires in ACSR conductors.

e) Observed deterioration of any part of the conductor system, including the connectors, splices, sleeves and dead-end connectors, is viewed to indicate deterioration of the conductor system as a whole. If the deterioration is verified to be isolated to particular conductor system component, then only that component is replaced.

OEB INTERROGATORY #116

Reference:
TSP-03-03, ISD-SR-19

Interrogatory:
At the above noted reference, Hydro One stated the following:

Hydro One uses an ESL of 90 years for overhead transmission conductors, although the life span of each conductor can vary between 50 and 120 years, as numerous uncontrollable variables affect conductor deterioration, including manufacturing material quality, location, orientation, local atmospheric pollution levels, weather cycles and stringing tension. Currently, about 5% of the overhead conductor fleet has reached or exceeded their ESL of 90 years.

a) Please compare the percentage of assets presently beyond ESL in each Hydro One asset category.

b) Does the conductor fleet represent the asset category with lowest percentage of assets operating beyond ESL among these categories?

c) Please confirm that outages directly caused by spontaneous conductor failure represent a small proportion of all Hydro One outages.

d) Please confirm that this program is proposing significant investments during this test period to replace substantial volumes of an asset class that presently has a better than average demographic profile as compared to other asset classes, and that represents a smaller system reliability performance risk than do other asset classes.

Response:

a) The following table provides a comparison for the percentage of major assets presently operating beyond ESL.

Major Asset	Population Beyond ESL in 2018	Percentage of fleet beyond ESL in 2018
Transformers	177 units	24.7%
Circuit Breakers	549 units	11.5%
Protection Systems	3363 units	27%
Conductors	1,389 circuit-km	4.8%
Wood Poles	14,400 poles	34%
Underground Cables	0	0%

b) No, the underground cable asset category has the lowest percentage of assets operating beyond ESL among the major assets presented in a).

c) Hydro One aims to proactively replace its deteriorated assets before they fail. As such, meaningful correlation between failure rates and fleet/system condition is not available. See I-01-OEB-125.

d) The line sections making up the projects listed in SR-19 have been verified through condition assessment to contain End-Of-Life ("EOL") assets, and so this investment is not driven by asset expected service life. Other criteria such as condition, historical performance, technology obsolescence, safety and reliability also play a role in justifying equipment replacement.

OEB INTERROGATORY #117

Reference:

TSP-03-03, ISD-SR-19

Interrogatory:

a) Please confirm that Figure 2 shows a failure at a compression sleeve.

b) What was the cause of failure in this case?

c) Would the failure have been avoided if the sleeve had been replaced prior to the failure event?

d) What was the condition of the remainder of the conductor system in the affected span?

Response:

a) – d) The failed conductor system pictured in Figure 2 is for illustrative purposes. The pictured conductor appears to have mechanically failed at the connector. Further details on this failure event are not readily available.

Witness: Donna Jablonsky

OEB INTERROGATORY #118

Reference:
TSP-03-03, ISD-SR-19

Interrogatory:

a) What was the direct cause of the conductor failure shown in Figure 4?

b) Did the conductor break at or near a splice point, or between splices?

c) What is the percentage of Hydro One conductor failures directly attributable to conductor breakage between splices for events that do not exceed the initial design parameters of the conductor?

Response:

a) - b) The failed conductor system pictured in Figure 4 is for illustrative purposes. Details of this failure event are not readily available.

c) This percentage quantity is not available. As presented in Exhibit B-1-1, TSP Section 2.2, page 58, conductor caused outages are tracked at the conductor system level and not at the conductor sub-components level.

OEB INTERROGATORY #119

Reference:

TSP-03-03, ISD-SR-19

Interrogatory:

a) Please confirm that the example in Figure 5 shows a failed splice rather than a failed conductor.

b) Please compare the relative cost of replacing a sleeve or dead end fitting versus the cost of replacing 3 to 4 km of conductor (i.e. the distance between splices for typical reel lengths).

c) Does Hydro One preferentially replace entire reels of conductor in situations where the conductor system deterioration is focused at sleeves and/or dead end fittings?

Response:

a) As stated in ISD SR-19, page 7, Figure 5 shows a fallen conductor as a result of an insulator failure.

b) The cost of replacing a single conductor connector is approximately 1/20th of the cost of replacing 3 to 4 km of conductor.

c) Hydro One does not preferentially replace entire reels of conductor in situations where a conductor system's deterioration is verified to be isolated to a conductor connector.

Witness: Donna Jablonsky

OEB INTERROGATORY #120

Reference:
TSP-03-03, ISD-SR-19, ISD-SR-20, TSP-03-01

Interrogatory:
At the third reference above, Hydro One stated the following:

Transmission line sections are comprehensively refurbished when major line components are verified through condition assessment to be deteriorated. Hydro One will invest $425 million to address end of life aluminum core steel-reinforced (“ACSR”) and copper conductor and structures (see ISD SR-19), and $493 million for near end of life ACSR conductor (ISD SR-20). These investments aim to replace a total of 2,127 km, including about 224 km of copper conductor, which is the oldest conductor type in the system and is obsolete since Hydro One can no longer mend certain broken copper conductors. Hydro One will also refurbish steel structures with associated conductors and other lines assets where it has determined that it is economical to replace the entire structure as part of the line refurbishment.

a) The tables above indicate that approximately 247 km of EOL ACSR Conductors are being replaced as part of SR-19 and approximately 775 km of EOL ACSR conductors are being replaced a part of SR-20. Earlier in the Filing Hydro One stated that a total of approximately 1,900 km will be replaced as part of SR-19 and SR-20 (2,127 km - 224 km = 1,903 km). Please reconcile these differences.

b) Table 3 indicates that approximately 580 km of copper conductors will be replaced, but earlier in the Filing Hydro One states that only 224 km of copper conductor would be replaced. Please reconcile these numbers.

c) Do projects listed in the above tables all involve replacement of 100% of the conductor on all phases in the affected segments?

d) Will all or most of the structures and hardware also be replaced at the same time?
e) In respect of the 1,900 km of conductor slated for replacement that is not copper:
    i. How many "events" or "customer delivery point interruptions" have been directly caused by failures of these conductors?

ii. What are the key drivers for replacement of the 1,900 km of ACSR conductor? If condition, please identify the condition deficiencies by percentage of line affected (e.g. corrosion, broken aluminum strands, birdcaging, etc.)

iii. Are any conductors proposed for replacement primarily due to the condition of splices? If yes, please list and quantify total km affected.

f) How will Hydro One account for copper salvage value associated with the 224 km of copper conductor replacements?

Response:

a) and b) Table 2 and 3 in ISD-19 differentiate planned projects by the driving asset type – EOL ACSR or Copper Conductor. This does not mean all line segments within these projects contain that asset type. In other words, the projects listed in ISD-19 Table 3 do not exclusively consist of copper conductors; some segments/spans within these packaged projects are made of other conductor types, predominantly ACSR conductors. Only condition verified high risk assets are replaced through line refurbishment projects. Hydro One is proposing to replace to following:

Line Refurbishment Grouping	Circuit-km of Conductor Replaced	Reference
Verified EOL ACSR and Copper conductors packaged into projects	859	ISD-19, Page 8 of 15
Verified Near EOL ACSR conductors packaged into projects.	812	SR-20 page 2 of 11
An additional 456 km of verified high risk conductors (3,680 km) that have yet to be packaged into projects.	456	ISD-19, Page 8 of 15 Exhibit B, TSP 2.2, Page 3 of 117
Total:	2,127	Exhibit B-1-1, TSP 2.3 Exhibit B-1-1, TSP 3.1

c) The projects listed in ISD-19 and ISD-20 replace most but not all conductors in the outlined line sections. Some line segments/spans within these projects contain more recently replaced spans, and therefore do not require replacement.

Witness: Donna Jablonsky

d) Only deteriorated assets are replaced. Most hardware and some wood poles are replaced. Lattice structures are rarely fully replaced. In most cases, replacing deteriorated lattice members is sufficient for restoring a lattice structure to its designed functionality.

e)
i. Between 2008 and 2018, 36 customer delivery points were interrupted as a result of failure among the 1903 km of ACSR conductor planned for replacement.
ii. Condition is the key driver for the replacement of the identified ACSR conductor. Hydro One assesses conductor condition through its condition assessment program. End-of-life (EOL) condition is established when a conductor can no longer safely and reliably perform its designed function. The threshold for this condition is aligned to the wind, ice, and the combined wind and ice loading design capability of the inspected conductor.
iii. None of the identified conductor replacements are driven specifically by the condition of the connectors.

f) Hydro One’s construction efforts take into account the salvage or recycling value of all removed assets, including that of removed copper conductors. Removed components are separated, sorted and processed by scrap yards or recycling facilities. In most cases, the revenue obtained from salvaged or recycled components subsidize the construction refuse disposal efforts for a project. Any additional revenue is applied as credit to the project, lowering the overall project cost.

OEB INTERROGATORY #121

Reference:
TSP-03-03, ISD-SR-19

Interrogatory:

a) Please explain the volatile inter-annual net investment costs shown in Table 7 for planned replacements during the test period, with specific focus on the inter-annual variations in the "Tx Line Refurb: Placeholder, Expected EoL Line Discoveries" line item.

Response:

a) The projects listed in Table 7 are in different stages of execution. Projects just starting out have relatively smaller expenditures in initial years, as this is when the work is planned and engineered (not constructed). Projects in construction execution have larger expenditures, as this is when material is ordered and the work is physically completed.

OEB INTERROGATORY #122

Reference:
TSP-03-03, ISD-SR-19

Interrogatory:
At the above noted reference, Hydro One stated the following:

As shown in Figure 1, demographics for Hydro One overhead conductors demographics that have reached and exceeded EOL is increasing, thereby necessitating the replacement of those deteriorated EOL conductors. Line refurbishment investments are increasing over the test year period as compared to historical years which reflects the increase in circuit kilometres that are being replaced.

a) The above statement appears to conflate demographics and EOL as replacement/refurbishment drivers. Please confirm that Hydro One establishes EOL by asset condition and not by demographic profile.

b) Please confirm that the EPRI study filed as TSP Section 1.4 Attachment #4 (Derivation of Overhead Conductor Hazard Function) demonstrated an inconclusive relationship between ACSR conductor age, corrosion zone and conductor condition.

Response:
a) Confirmed, Hydro One establishes EOL through asset condition assessment and not demographic profile.

b) As summarized in Exhibit B-1-1, TSP Section 1.4, Attachment 4, page 97 of 98, EPRI demonstrated that there is no useful correlation relating conductor condition to individual parameters including corrosivity of location, conductor size or conductor stranding. However using Weibull models (probabilistic description of population) EPRI was able to relate the condition of the conductor population to age.

OEB INTERROGATORY #123

Reference:

TSP-03-03, ISD-SR-19

Interrogatory:

At the above noted reference, Hydro One stated the following:

The following factors also influence the costs of Line Refurbishment Projects:

- The circuit voltage level, site accessibility, structure type (wood pole vs. steel structure);
- The length of conductor being replaced;
- Whether replacement of deteriorated shieldwire, insulators, or additional hardware is required; and
- Any structure or foundation work required.

a) Do Hydro One conductor replacement projects typically (or always) include replacement of suspension hardware, armour rods and vibration dampers/spacer dampers? Please list any other equipment or hardware typically replaced at the same time as conductor.

Response:

a) Hydro One transmission line refurbishment projects aim to replace all condition verified deteriorated assets within the project scope. This includes conductor suspension hardware, dampers/spacer dampers and armour rods where required.

OEB INTERROGATORY #124

Reference:

TSP-03-03, ISD-SR-20

Interrogatory:

Table 1 contains information from the projection model. It shows that the amount of circuit kilometers of conductors expected to be in high risk condition over the next twenty years is about 42% of the fleet. As such, it is prudent for Hydro One to proactively engage in conductor replacement, so to ensure that the collective High Risk conductor assets are managed in a timely manner that maintains system reliability and limits the safety risks. Failure to address the issue proactively would result in unmanageable risk and Hydro One will be in a position where it would not be feasible, even impossible, to manage the set of cumulative assets deteriorated to EOL condition.

a) Are the values in Table 1 net of the replacements proposed in the line refurbishment projects identified in SR-19?

b) Is "high risk condition" as used in this paragraph synonymous with "beyond ESL"? If not, what is the basis for predicting that 42% of the fleet will be in High Risk Condition?

c) Are all conductors in Hydro One's fleet that are presently beyond ESL considered to be in High Risk Condition?

d) What is the total percentage of Hydro One's conductor fleet that would be beyond ESL in 20 years if no conductor replacements were implemented under a conductor-condition driven program?

e) What proportion of Hydro One's conductor fleet is presently replaced each year under programs and projects other than this conductor-condition driven program? Does that value consider the average amount of transmission line replaced each year as part of storm restoration activities, including force majeure events?

Witness: Donna Jablonsky

Response:

a) Table 1 in ISD-SR-20 is taken from the EPRI report in Exhibit B-1-1, TSP Section 1.4, Attachment 4. It is a projection of how many additional circuit-km of conductor will enter end-of-life or near end-of-life condition over the next 5 years. This would be in addition to the already verified 3,680 circuit-km of high risk conductors in the system, which ISD-19 and ISD-20 aim to address.

b) The projections made by the EPRI report are not synonymous with "beyond ESL". As per Exhibit B-1-1, TSP Section 1.4, Attachment 4, projections were developed from EPRI Weibull models.

c) No, Hydro One assesses conductor condition through its condition program and not by age.

d) 32% of the transmission conductor fleet will be beyond ESL in 2040 without any further replacements.

e) A very small portion of overhead conductors are replaced through projects and programs other than the Line Refurbishment investments (SR-19 & SR-20).

OEB INTERROGATORY #125

Reference:

TSP-03-03, ISD-SR-20

Interrogatory:

At the above noted reference, Hydro One stated the following:

Operating a circuit with near EOL conductors subjects that circuit to an increased likelihood of failure, which threatens reliable operation of the system. Line refurbishment will alleviate this threat.

a) What is the average annual likelihood of conductor failure per Hydro One circuit km? The answer should only refer to outages directly caused by conductor failure, and should not include outages caused by structure, hardware, insulator or splice/deadend failures, loading conditions that exceed the design specifications, or by contact between conductors and trees, other conductors/shieldwires, vehicles, buildings, the ground or other objects.

Response:

a) The requested measure for failure "per circuit km" is not a recognized reliability measure and its interpretation as a standalone measure is not meaningful.

However, to show a quantitative relationship between conductor failure rates and conductor fleet condition we can look at the difference in interruptions among known deteriorated conductors versus the overall fleet:

As noted in Interrogatory I-01-OEB-120 part e) i), between 2008 and 2018, 36 delivery points were interrupted as a result of failures along the 1903 circuit-km of ACSR conductor planned for replacement. This corresponds to 0.02 delivery point interruptions per km.

In comparison, the overall fleet of 29,107 circuit-km of conductor experienced 126 delivery point interruptions between 2008 and 2018. This corresponds to 0.004 delivery point interruptions per km.

Therefore, the 1903 circuit-km of conductor planned for refurbishment is presently demonstrating five times more delivery point interruption when compared to the overall fleet.

OEB INTERROGATORY #126

<u>Reference:</u>
TSP-03-03, ISD-SR-21

<u>Interrogatory:</u>
At the first reference above, Hydro One stated the following:

The Program targets the replacement of approximately 800 wood poles each year, totaling 4000 wood poles over the five year planning period. Hydro One has evaluated various alternatives for the Program, as described below and concluded that the most cost effective and efficient undertaking is to proactively replace end of service life wood poles. The projected costs of the Program are estimated to be $156.1 million over the 2020-2022 test period.

At the second reference above, Hydro One stated the following:

Investment Name: 2017-2018 TX Wood Pole Replacements
The wood pole structures scheduled for replacement in the test years will be replaced with new wood pole or composite structures. The proposed plan will be to replace approximately 850 wood poles in each of the test years 2017 and 2018. This represents an average annual replacement rate 2%. This rate of replacement has been able to keep pace with end of life wood poles identified through inspections as well as address other known wood pole deficiencies, such as the Gulfport structures, on the transmission system.

a) In its previous TSP filing (EB-2016-0160), Hydro One proposed to replace approximately 850 wood poles in 2017 and 2018 to keep pace with end of life wood poles as part of the S75 project "2017-2018 Tx Wood Pole Replacements".
    i. How many wood poles were replaced in each of 2017 and 2018?
    ii. What percentage of the wood poles replaced in years 2017 and 2018 were end of life wood poles planned for replacement?
    iii. How many wood poles were replaced in 2019 (to date), and how many are planned for replacement for the remainder of 2019?
    iv. How many wood poles planned for replacement over the last 3 years were not replaced, and have been subsequently deferred into this test period?

v. What is the expected deterioration rate of wood poles that were not at end of life at the time of the last application? In other words, what percentage of the fleet will incrementally deteriorate into end of life condition in each year of the test period?

b) Please describe and provide rationales for changes made to the pole replacement program since Hydro One's previous filing (cost-wise and number of poles).

Response:

a)

i. 966 structures were replaced in 2017 and 735 in 2018 as found in Exhibit C-2-1 Attachment 1 page 35 and 54.

Exhibit B-1-1 TSP-03-03 Table 4 needs to be amended with the actual historical numbers, as follows:

	Historical				Bridge	Test			Plan	
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Wood Pole Portfolio										
# of Replacements	845	888	966	735	560	800	800	800	800	800
% of Fleet	2.0%	2.1%	2.3%	1.8%	1.3%	1.9%	1.9%	1.9%	1.9%	1.9%

ii. All replaced structures were EOL. More replacement candidates are released than the annual replacement target, to account for outage cancellations and other factors that temporarily halt a replacement. Thus there is always carry-over from one year to the next. Approximately 86% in 2017 and 76% in 2018 were planned for replacement in those years. The rest were planned carry-over structures from the previous year.

iii. As of the end of June 2019, 391 structures were replaced and 459 are planned for replacement for the remainder of 2019.

iv. Please refer to a) ii.

v. End of life is a function of various factors such as type of wood, treatment, weather, presence of pests, etc. Furthermore, wood poles are not engineered materials and the quality is not uniform and predictable. Therefore, Hydro One can only reliably determine wood pole end of life through condition assessment.

Based on historical rates of assessment, approximately 1.5% of the fleet will be discovered to be at end of life each year of the test period.

b) The number of yearly units for the Test years have decreased slightly (800) from the previous filing (850). These changes are due to Hydro One's decision during 2018 Business Planning to disaggregate wood pole investments and target only high criticality, publicly accessible locations. This approach resulted in a higher unit cost, due largely to higher costs required to mobilize resources for one-off replacements.

OEB INTERROGATORY #127

Reference:
TSP-03-03, ISD-SR-21

Interrogatory:
a) Please provide a count of the wood pole failures identified in Figure 4 during 2016 and 2017 that were caused by:
- force majeure events
- extreme wind, snow or ice loads in excess of original design parameters
- contacts with vehicles
- treefalls

Response:
a) Figure 4 shows the forced outage frequency on a circuit due to a wood pole failure. Hydro One's performance analysis does not include underlying/contributing factors (i.e extreme weather, vegetation, or contact with vehicles) that may have caused the wood pole failures. Therefore, it is not possible to break down the wood pole outage data in Figure 4 any further.

OEB INTERROGATORY #128

Reference:
TSP-03-03, ISD-SR-24

Interrogatory:
At the first reference above, Hydro One stated the following:

If EOL shieldwire is not replaced, it is likely to break and make contact with the conductor, resulting in a circuit outage and potential customer interruption.

At the second reference above, Hydro One stated the following:

Hydro One will invest $64 million over the five-year plan to assess and replace shieldwire that does not meet current design requirements (ISD SR-24). This will address shieldwire that is at risk of mechanical failure (including falling to the ground).

a) What is the average annual probability of shieldwire failure in the segments identified in this program over the test period, expressed as expected annual failures per circuit km?

b) What is the basis of not meeting current design requirements?

c) Is the shieldwire replacement primarily condition driven, or has Hydro One done engineering to demonstrate that even good condition shieldwires are at risk of mechanical failure due to excessive span length, or interference with phase conductors due to heavy loading sag and/or galloping risk? Please provide details.

Response:
a) Hydro One does not have sufficient data to determine the average annual probability of end-of-life shieldwire failure at this time. However, the count of delivery point interruptions amongst known deteriorated shieldwire can be compared to the delivery point interruptions of the overall fleet:

Between 2008 and 2018, 36 delivery points were interrupted as a result of failures along the 1740 circuit-km of shieldwire planned for replacement from 2019-2023. This corresponds to 0.02 delivery point interruptions per km.

In comparison, the overall fleet of 34,644 circuit-km of shieldwire experienced 139 delivery point interruptions between 2008 and 2018. This corresponds to 0.004 delivery point interruptions per km.

Therefore, the 1740 circuit-km of shieldwire planned for refurbishment is presently demonstrating five times more delivery point interruptions when compared to the overall fleet.

b) Copperweld shieldwire is an older type of shieldwire that was installed in limited quantities across the Hydro One network. This shieldwire is not capable of adequately sustaining lightning strikes and is therefore targeted for replacement. This is the only type of shieldwire currently installed on Hydro One’s system with known design deficiencies.

c) Shieldwire replacement is condition driven. Overall shieldwire condition is assessed and used to determine when the shieldwire has reached end of life. If shieldwire was found to be at risk of mechanical failure or interference with phase conductors, it would be considered to be in poor condition and would be scheduled for replacement.

OEB INTERROGATORY #129

Reference:
TSP-03-03, ISD-SR-25, TSP-03-01, TSP-01-04

Interrogatory:
At the first reference above, Hydro One stated the following:

A. OVERVIEW
Transmission Lines Insulator Replacement Program (the "Program") involves primarily the replacement of defective porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1965 and 1982. These defective insulators are used province-wide in Hydro One's transmission system.

At the second reference above, Hydro One stated the following:

As noted above, porcelain insulators manufactured by COB and CP between 1965 and 1982 are known to be defective and susceptible to mechanical and electrical failure. There are approximately 34,000 circuit structures with defective porcelain insulators, including about 15,000 that have been identified as being on structures in critical locations (i.e., near roads, water railways, urban areas, golf courses, educational and health care facilities). Failed insulators typically result in a sustained forced outage because of the resulting permanent electrical fault. Repair time can be prolonged, averaging 36 hours per outage, depending on the location and severity of the failure. To date, Hydro One has replaced approximately 8,900 publically accessible COB and/or CP insulators.

At the third reference above, Hydro One stated the following:

In 2016, investment in transmission stations saw an overall increase of $147 million to address deteriorated, poor condition assets in addition to projects from previous years that were under construction and had significant portions carry over into 2016 including work at Allanburg TS, Gerrard TS, and Beck 2 TS. Transmission line refurbishments contributed $62 million to the overage due to increased wood pole replacement needs based on poor condition and increased expenditures to replace defective CP/COB insulators to mitigate public safety risk.

At the fourth reference above, Hydro One stated the following:

After testing 591 samples, EPRI found overwhelming evidence to support the recommendation that Hydro One should remove the fleet of COB and CP porcelain insulators from service as soon as is practically possible to mitigate the risk of safety and reliability. Based on the results of Phase 2 COB/CP testing, insulators posing a higher public safety (i.e. insulators in critical locations) will be replaced by 2022 at a rate of approximately 3,700 circuit structures per year.

a) In which year were serious problems with COB porcelain insulators first identified?

b) How many of the problematic COB insulators have been replaced each year since the problems were first identified (expressed either as total number of bells replaced, or total percentage of the initially identified problematic COB bells replaced).

c) What percentage of the originally identified problematic COB porcelain bells are still in service in the Hydro One system at present?

d) Hydro One received approval to replace a large number of COB porcelain insulators in its prior cost of service filing.
   i. What percentage of the 2016 COB insulator fleet was replaced since the last filing?
   ii. What percentage of the COB insulator replacements planned for the past test period was deferred? Quantify the associated deferred capital cost and provide the reasons for the deferral.

e) What proportion of the 2016 COB insulator fleet will have been replaced by 2024 if the replacement program proposed in this TSP is followed?

f) What will be the residual percentage (or count) of COB insulator fleet expected to be left to replace following the present planning period?

g) In the second reference, please confirm that the last sentence in the above reference refers to 8,900 COB insulator bells rather than 8,900 insulator strings.
   i. If confirmed, how many structures does this represent?

h) How many faulty COB insulator bells are installed on the 34,000 circuit structures with defective insulators and the 15,000 in critical locations referred to in the above paragraph?

i) Please provide all-in cost of replacing COB insulators each year from 2015 to 2019.

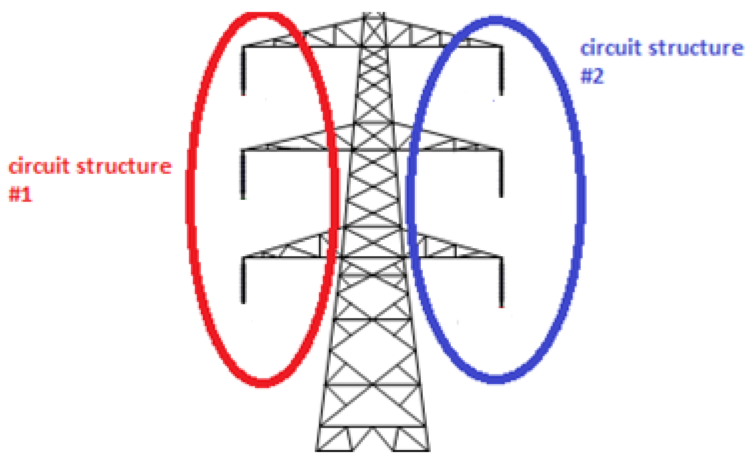
j) How many insulator bells were replaced in each year from 2015 to 2019?

k) What was the average all-in replacement cost per bell in each year (categorized by bell strength rating, as appropriate)?

l) Has Hydro One modified its specification and procurement processes to ensure that similar porcelain insulator issues are avoided in future widespread applications?
   i. If yes, please provide details.
   ii. If no, please explain why not.

Response:

All responses provided are in terms of circuit structure. A circuit structure configuration is shown below.



a) Serious problems were first identified in 2015 when an insulator failure resulted in a conductor drop on a parking lot.

b) The annual number of insulators (by circuit structure) replaced are shown below:

2015	**2016**	**2017**	**2018**
155	2100	3422	3900

c) Approximately 70% of the total defective fleet is currently in-service.

d)

i. Since the last filing approximately 30% of the total defective fleet has been replaced.

ii. There were insignificant carry-overs (<1%) from the previous test period.

e) By the beginning of 2024, we anticipate that 80% of the defective fleet will be replaced. In 2024 we are expecting to replace 10% of the defective fleet.

f) Approximately 10% will be left to replace after 2024.

g) “8900” refers to 8900 circuit structures.

h) All insulator shells on the 34,000 circuit structures are the faulty COB/CP insulator. This number includes the 15,000 critical circuit structures.

i) Please see below:

2015	**2016**	**2017**	**2018**
$2.9M	$29.5M	$49.8M	$65.8M

j) Please refer to part b).

k) The 2016-2018 average insulator replacement costs, per circuit structure, are shown below:

Str. Function	2016-2018		
	500kV	**230kV**	**115kV**
Dead-End	$58,278	$26,929	$23,504
Suspension	$20,084	$11,995	$10,423

l) Hydro One follows CSA insulator standard 411.1. In the current version, there is a mandatory testing procedure that outlines cement expansion limits to ensure cement expansion issues are avoided in the future.

OEB INTERROGATORY #130

Reference:
B-02-01

Interrogatory:
a) Does Table 1 account only for the cost of projects and programs identified in the prior filing?

b) Please identify all projects in the prior filing that were not completed as planned.

c) Please identify the percentage of spending by program in the prior filing not completed as planned, or in excess of plan.

d) What was the average variance in percentage between estimated cost and final cost for the projects identified in the prior filing, and what was the standard deviation around that average variance?

e) What is the total value of projects and programs identified in the prior filing that have been deferred into the present planning period?

Response:
a) The values shown in *Table 1: Capital and In-Service Additions Performance* represent all capital expenditures and in-service additions for both planned and unplanned projects and programs.

b) In reference to Exhibit C, Tab 2, Schedule 1, Attachment 1, Capital Program Performance Report, the following projects did not complete as planned:

1. S10 Integrated Station Component Replacements - Dryden TS
2. S17 Station Re-Investment - Wanstead TS
3. S21 Station Re-Investment - Barrett Chute SS
4. S31 Integrated Station Component Replacements – Ear Falls TS
5. S36 Station Re-Investment - Leaside TS
6. S43 Integrated DESN Replacement – National Research Council TS
7. S47 Station Re-Investment - St. Isidore TS

8.	Other	Eastern Zone Station/Yard Investments
9.	Other	Integrated DESN Investments - Kingsville TS
10.	Other	GTA Metalclad Switchgear Replacements
11.	Other	Western Zone Station/Yard Investments
12.	Other	Campbell TS: T1, T2 Transformer Replacement
13.	S59	CIP-014 Physical Security Implementation
14.	Other	L3P/L4P Telecom and Protection Upgrade
15.	Other	BSPS Replacement
16.	S64	Line Refurbishment - C1A/C2A/C3A
17.	S83	H7L/H11L Cable Replacement
18.	D01	Clarington TS: Build new 500/230kV Station
19.	Other	Copeland MTS: Build line connection for Toronto Hydro
20.	Other	Major Risk Mitigation

c) The table below captures the percentage of spending by program in the prior filing period not completed as planned, or in excess of plan (in $ millions). As you can see Hydro One manages well at the category and sub-category level. For a detailed program level report including variance explanations please refer to C-02-01-01 Capital Program Performance Report.

	2017 Actuals	2017 DRO Forecast	2017 % Spend	2018 Actual	2018 DRO Forecast	2018 % Spend
SUSTAINING CAPITAL						
Transmission Stations						
Circuit Breakers	0.4	0.4	100%	0.1	3.0	3%
Power Transformers	0	1.1	0%	-0.7	0.5	-140%
Other Power Equipment	0	0.1	0%	0.3	0.2	150%
Ancillary Systems	1.1	1.2	92%	0.7	0.5	140%
Station Environment	0.4	0.2	200%	0	0	0%
Integrated Station Investments	481.0	469.0	103%	410.7	397.4	103%
TX Transformers Demand and Spares	26.8	28.2	95%	82.6	67.2	123%
Protection and Automation	20.9	27	77%	44.4	58.1	76%
Site Facilities and Infrastructure	13.0	13.8	94%	16.7	10.6	158%
Total Transmission Stations Capital	**543.6**	**541.0**	**100%**	**554.9**	**537.5**	**103%**
Transmission Lines						
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	196.3	196.5	100%	225.6	227.8	99%
Underground Cables Refurbishment and Replacement	10.7	7.2	149%	16.5	30.1	55%
Total Transmission Lines Capital	**207.1**	**203.7**	**102%**	**242.1**	**257.9**	**94%**
TOTAL SUSTAINING CAPITAL	**750.6**	**744.7**	**101%**	**796.9**	**795.4**	**100%**
DEVELOPMENT CAPITAL						
Inter Area Network Transfer Capability	36.0	36.0	100%	48.9	39.0	125%
Local Area Supply Adequacy	45.1	46.9	96%	20.7	28.0	74%
Load Customer Connection	42.3	33.8	125%	28.5	18.1	157%
Generator Customer Connection	0.4	0	-	0.3	1.2	25%

Witness: Andrew Spencer

	2017 Actuals	2017 DRO Forecast	2017 % Spend	2018 Actual	2018 DRO Forecast	2018 % Spend
P&C Enablement for Distributed Generation	0.8	0.6	133%	0.5	0	-
Risk Mitigation	9.5	10.9	87%	2.6	4.3	60%
Power Quality	2.3	2.3	100%	1.4	4.1	34%
TS Upgrades to Facilities Distribution Generation	0	0	0%		0	0%
Performance Enhancement	0	0	0%	0	0.3	0%
Smart Grid	0.7	0.9	78%	0.2	0	-
TOTAL DEVELOPMENT CAPITAL	**137.1**	**131.4**	**104%**	**103.1**	**94.9**	**109%**
OPERATIONS CAPITAL						
Grid Operating and Control Facilities	6.0	7.7	78%	3.8	29.1	13%
Operating Infrastructure	4.8	5.4	89%	5.8	13.8	42%
TOTAL OPERATIONS CAPITAL	**10.8**	**13**	**83%**	**9.6**	**42.9**	**22%**
CAPITAL COMMON CORPORATE COSTS & OTHER COSTS						
Transport and Work, and Service Equipment	16.9	17.5	97%	9.3	16.6	56%
Information Technology (including Cornerstone)	32.8	34.4	95%	42.0	28.9	145%
Facilities & Real Estate	6.7	9.1	74%	7.0	21.3	33%
Other (including CDM)	-1.1	0	-	-0.7	0	-
TOTAL CAPITAL COMMON CORPORATE COSTS & OTHER COSTS	**55.3**	**60.9**	**91%**	**57.6**	**66.8**	**86%**
TOTAL TRANSMISSION CAPITAL	**953.9**	**950.0**	**100%**	**967.3**	**1,000.0**	**97%**

d) The average variance on estimated spend versus actual spend for projects in the last filing was 9% and the standard deviation around the average variance is 74%

e) There were 20 projects (see above) that had an in-service date identified within the last filing period that was delayed into future years. The net variance associated with these 20 projects was $-95.3M. There were also projects which had elements accelerated into the last filing period from future years to mitigate risks within the overall capital envelope, which together totaled approximately $100M. Details are available in Exhibit C-02-01-01 Table 39. Hydro One must maintain flexibility within the overall investment portfolio to accommodate new circumstances that may arise over the course of a multi-year project such as outage constraints, external approvals, material delivery, site conditions, changing priorities, etc. Hydro One uses its judgment and expertise to respond to these changing conditions and strives to work with in the capital envelope to meet its stated objectives.

There were 7 programs that had portions deferred into future years. The total amount deferred was approximately $45M due to project delivery issues including cancelled outages and reprioritization of resources. For program performance please refer to Exhibit C, Tab 2, Schedule 1, Attachment 1, Capital Program Performance Report.

OEB INTERROGATORY #131

Reference:
TSP-02-01

Interrogatory:
At the above reference, it is stated that:

As changes to investments or other circumstances occur during the year, Hydro One reprioritizes during execution as new information may change one or more projects' expected value, timing, cost, customer needs, etc. In 2017, Hydro One formalized a Redirection Committee to appropriately redirect funds or authorize additional spending as necessary. Such redirection or allocation allows prudent and timely adjustments to be made to the work originally identified in the investment plan.

The Redirection Committee meets once a month. Following the review and recommendation of plan adjustments, investment level decisions are documented and communicated to appropriate stakeholders, including the recommended change and rationale. Updates regarding significant Redirection Committee decisions, as well as recommendations related to reprioritization options that require an approval authority that exceeds that of members of the committee are communicated to the ELT.

a) Please quantify the investment adjustment decisions, at the project/program level, made by the Redirection Committee on a monthly basis for 2017 and 2018.
   Please also:
   i. Provide examples of "significant Redirection Committee decisions".
   ii. Explain the rationales of adjusting investment plans.
   iii. Explain how the reprioritization options were selected.

Response:
a) The redirection process was formalized in Q4 of 2017. Below is the number of redirection decisions by month, from October 2017 through December 2018:

2017			2018											
Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
0	1	0	2	8	2	0	17	13	3	4	2	0	1	0

i. Reprioritization of the Private Cloud Data Center project ahead of several small IT investments which were deferred to future years to enable the realization of $13M of OM&A reductions over two years.

Advancement of approximately 50 critical Transmission Station roof repairs to mitigate the likelihood of roof failures resulting in forced outages, posing a reliability risk.

ii. Adjustments to the investment plan are made in response to prevailing industry and/or corporate circumstances, including customer and regulatory commitments or compliance to industry standards. The rationale for individual investment redirections are categorized as below:

Category	Definition
Pre-Release Estimating Variance	Variance between planning assumptions and final estimate.
Acceleration	Advancement of work from a future period.
Deferral (Planned)	Deferral of work to a later period due to factors within Hydro One's control.
Deferral (Unplanned)	Deferral of work to a later period due to factors outside of Hydro One's control.
Reduction	Reduction of work in current period; no explicit intention to make up difference in future period.
Cancellation	Cancellation of investment included in baseline plan.
Unforeseen Investment	New investment not previously included in baseline plan resulting from emergent need.

iii. Selections are made based on a variety of factors including: safety and reliability risks, customer needs/commitments, and productivity/savings.

OEB INTERROGATORY #132

Reference:
C-01-01, A-03-01, TSP-01-03

Interrogatory:

a) Table 2 above indicates that Hydro One's Transmission Rate Base is growing significantly faster than inflation, while the forecast load peak is decreasing (per Table 5). Please explain the reason for this inverse relationship.

b) Was the net impact of 8.7% on 2020 average transmission rates shown in Table 14 communicated to customers during the customer outreach sessions? If yes, please provide documentation.

c) Was an 8.7% year-one (i.e. 2020) rate increase assumed when calculating any of the average annual transmission rate increases shown in Illustrative Scenarios A, B, C or D (Reference 4)?
   i. If yes, please identify which scenario.
   ii. If no, please explain why not.

d) Were the average annual rate increases shown in the Illustrative Scenarios calculated using the same methodology shown in Table 14, i.e. considering the net impact of both revenue requirement growth and declining load forecast?
   i. If no, please show what the average annual transmission rate increases would have been for all Illustrative Scenarios if the rate calculations had followed the same methodology.

Response:

a) Hydro One’s rate base growth is driven by in-service additions resulting from capital investments that are informed by asset condition assessments; reliability, safety and environmental sustainability requirements; system renewal regional development; new customer connections; and customer needs and preferences.

   The decline in peak load is forecast due to a combination of slowing economic growth and conservation initiatives. There is no direct relationship between the two.

b) No, the direct impact of 8.7% in 2020 was not directly communicated to customers as part of the engagement. Customer engagement occurred prior to the investment plan being developed.

c) No; the rate impacts shown in all scenarios reflected only the base revenue requirement and associate rate change, excluding load factor, variance accounts and external revenue. The basis of the customer engagement focused on inputs (level of investment) and resulting outcomes (reliability performance, reliability risk, etc.); the impact of these other factors would be consistent across all scenarios and was completed prior to the development of the investment plan. See responses to OEB-87b) for information on customer preferences in terms of investment levels and rate impacts as indicated in through the Customer Engagement Survey.

d) Please see response to part c) above. If the scenarios had been calculated consistent with the methodology in Table 14 (i.e. including load factor, variance accounts and external revenue), the following rate impacts would have been presented:

	A	**B**	**C**	**D**
5-Year Average Rate Increase	3.1%	5.2%	7.1%	7.6%

OEB INTERROGATORY #133

Reference:
C-02-01-01

Interrogatory:
At the above noted reference, Hydro One stated the following:

In its subsequent "DRO Update" dated November 16, 2017 which was submitted in response to the DRO Order, Hydro One addressed the points raised by the OEB in the DRO Order with an explanation about how it allocated capital reductions in the draft rate order for 2017 (where possible) and 2018 by providing the following additional information:

- In "Overhead Lines Refurbishment Projects, Component Replacement", the company reduced the tower coating and shieldwire replacement programs and its deferred line refurbishment projects.
- In "Integrated Stations", at the time the Decision was issued, 98% and 75% of the portfolios for 2017 and 2018, respectively, were already in execution. Cancelling those projects would result in significant inefficiencies and stranded costs. Deferring the remaining 25% of the 2018 "Integrated Stations" projects would negatively impact reliability. These projects include investments at Kingsville, Leaside, Cherrywood, Sheppard, Detweiler, Minden, Gage and Stanley transformer stations.
- Reductions in the Development capital forecast were largely driven by changes in customer demand and project forecasts. The Development projects most impacted are investments at Clarington TS (-$38 million), Lisgar TS (-$7 million), Runnymede TS (-$13 million) and Hanmer TS (-$8 million).

a) Were the deferrals mentioned in the first bullet based upon Hydro One's assessment that they represented lower reliability performance and safety risk than projects that were not deferred?

b) Please explain in detail how changes in customer demand and project forecasts influenced the reductions listed in the third bullet.

<u>Response:</u>

a) The deferrals referenced considered specific OEB feedback with regards to the pacing of tower coating [and the prioritization of near-term risk mitigation opportunities ahead of NPV and longer-term risk mitigation opportunities based on] the relative risk-spend efficiency of different candidate investments based on project cost and mitigation of safety, reliability, and environment risks.

b) In reference to the reductions in the Development capital forecasts the following variance explanations are provided below:

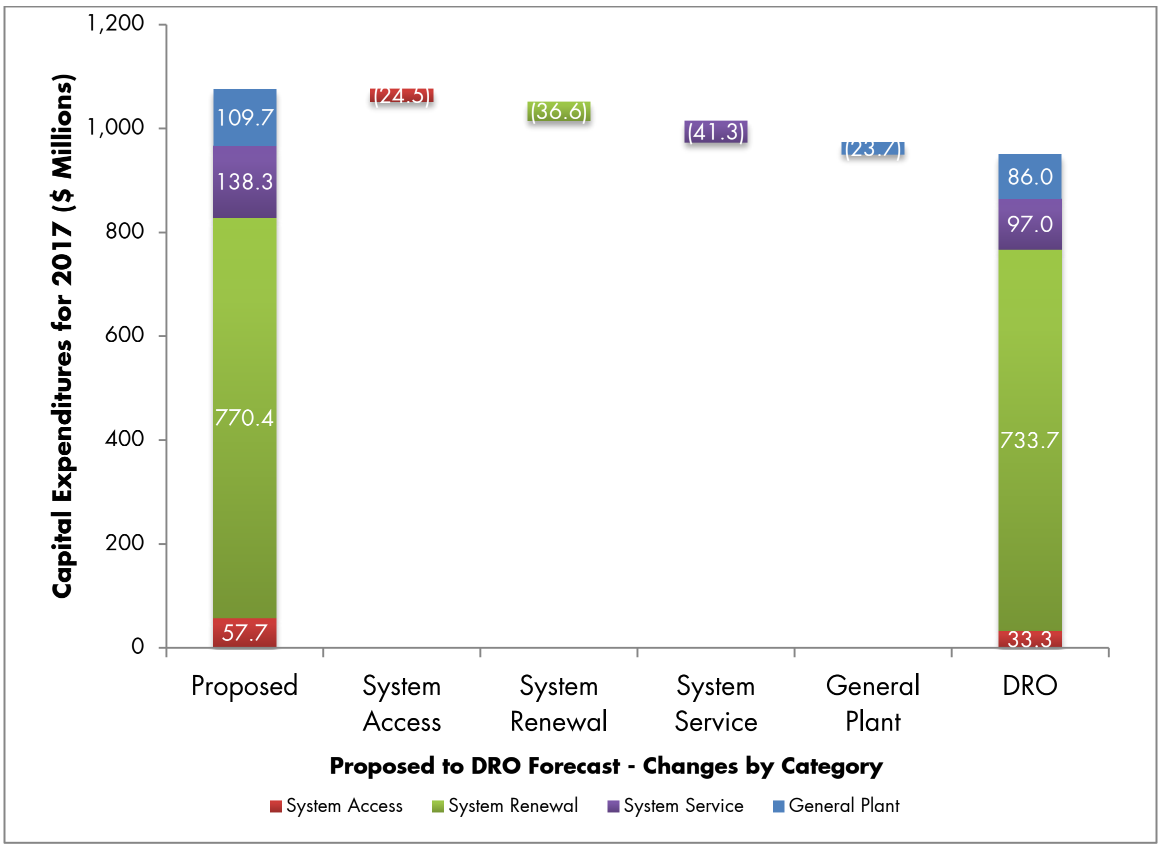
   i. The Clarington TS forecast reductions were driven by risks that did not materialize;
   ii. Lisgar TS was cancelled at the customer's request;
   iii. Runnymede TS costs were reduced as a result of lower material costs and a decrease in contingency for risks that did not materialize; and
   iv. The investment at Hanmer TS was to be a new 230-44 kV 83MVA load delivery station that was cancelled due to area load forecast being lower than previously projected.

OEB INTERROGATORY #134

Reference:
C-02-01-01

Interrogatory:
a) Please provide the information in Figure 1 categorized using the standard OEB classifications (System Access, System Renewal, System Service and General Plant).

Response:
a) Please find below the corresponding Figure 1 with OEB classifications:



OEB INTERROGATORY #135

Reference:
EB-2018-0098, Exh B/Tab 5/Sch 1/p.1

Interrogatory:
At the above noted reference, Hydro One stated the following:

Alternative 2 – Perform one or a combination of the following; Increase operating temperature, replace existing wood poles with higher structures, increase conductor tension on existing wood poles.

The three design alternatives identified in Alternative 2 are cost effective only if the conductor is in fair condition, and has considerable service life remaining. The existing conductor is of 1950 vintage and it is predicted to have approximately 10-15 years of service left before reconductoring is required. This reconductoring due to age/end of life will be required in the near future regardless of any interim design solutions to help increase the thermal ratings. Consequently, to achieve cost synergies and to avoid double customer and community construction impacts over a short time period, Alternative 2 was not explored further.

a) What conductor ESL was assumed in this remaining life assessment?

b) What would the remaining service life have been if a 90 year ESL had been used?

c) Would a remaining conductor service life of 30 to 35 years have been considered adequate to justify considering the Alternative 2 modifications? Would it have been physically possible to upgrade the line to meet the IESO's ampacity requirements for H9K using a combination of the Alternative 2 modifications?
    i. If yes, what is the estimated cost of implementing the required modifications?

d) What was the assessed overall condition of the existing conductor, poles, hardware, insulators, shield wires and other components of H9K at the time the Leave to Construct application was initially filed with the OEB?

Response:

Hydro One notes that the Kapuskasing Area Reinforcement Project has already received OEB approval pursuant to Section 92 of the *OEB Act, 1998*. Alternatives to this Project to address the need identified by the IESO were already reviewed by the OEB in the Leave to Construct ("LTC") Application proceeding (EB-2018-0098).

a) At the time of the LTC Application (EB-2018-0098) the H9K circuit had an Expected Service Life ("ESL") of 70 years.

b) The line was built in 1951. At the time of the LTC Application (EB-2018-0098) the line was already 67 years old. If a 90 year ESL was applied, then the remaining ESL would have been about 23 years.

c) The remaining service life assuming a 90 year ESL is not 30 to 35 years as explained in response to part (b) above. Based on the condition assessment the remaining life was predicted to be 10 to 15 years. As such Alternative 2 modifications would not have been justified.
    i. Not applicable based on response to part (c).

d) At the time of the LTC Application (EB-2018-0098), the H9K circuit was 67 years old. The overall assessed condition of the H9K circuit (conductor, shield wire, hardware and insulators) showed signs of deterioration. The condition assessment predicted a remaining life of 10 to 15 years.

OEB INTERROGATORY #136

Reference:
EB-2018-0098, Exh B/Tab 7/Sch 1/p.1, Table 1

Interrogatory:

a) The original cost estimate for the “10 MVAr reactive support” project component was $4 million. What is the current estimate for this component?

b) The original cost estimate for the “10 MVAr capacitive support” project component was $2 million. What is the current estimate for that component?

c) What was the initial estimate quality associated with each of these components, using the AACE estimate classification system and also expressed in terms of +/- percentage range?

d) What is the present estimate quality for each of these components using the same system?

e) Does the updated estimate include other incremental substation components that cannot be classified as either reactive support or capacitive support and cannot be attributed prorata to either of those primary project components? Please provide details of all such unattributed project components and explain why they are now required to satisfy the IESO's functional specifications for the KAR project.

f) Did Hydro One inform the OEB of the initial estimate quality and range when the LTC application was submitted?

g) Did Hydro One inform the OEB of the present estimate quality and range when submitting the revised cost estimates in March 2019?

h) Please provide a detailed description of all site-specific and non-site-specific factors that were considered when Hydro One developed the initial reactive and capacitive support project component estimates.

i) What new information became available following the initial LTC application regarding each of these project components that informed the cost variances identified in the revised estimates filed with the OEB in March 2019?

j) What additional design and procurement work has been done between the time the initial LTC application was submitted and the issuance of the revised cost estimate?

k) Has project scope changed since the initial cost estimate?
   i. If yes, what triggered the scope change?
   ii. If yes, were all changes authorized through Hydro One's project management process?

l) What are the detailed drivers that caused the variance between the initial and revised cost estimates?

m) Did Hydro One originally estimate the substation component additions as if this was a greenfield project, or was the initial estimate developed with the understanding that this is a brownfield renovation-type project?

n) Would Hydro One consider it to be good utility practice to develop a brownfield construction estimate using greenfield construction site assumptions?

o) Did Hydro One apply the same level of estimate diligence and expertise to estimating costs for the substation components as it applied to estimating the line component costs? If no, please explain why not.

p) What would Hydro One do differently in preparing and submitting a Leave to Construct application for a similar facility today?

Response:

a) The current Class 3 cost estimate provided to the OEB in March 2019 was $17.3 million and included the installation of both reactor and capacitor bank. Individual cost estimates for reactive and capacitive devices were not prepared as both devices were required.

b) Please see response to part (a) above.

c) As documented in the LTC Application for this Project, the initial estimate quality of the station component of this investment was referenced as being preliminary in nature, and made no reference to an AACE or accuracy range.

d) The current estimate quality for the station component is AACE Class 3 with an accuracy of -20% to +30%.

e) The current estimate provided to the OEB in March 2019 does not include incremental facilities or substation components beyond those required to meet IESO requirements.

f) Please see response to part (c) above.

g) In the March 2019 letter the OEB was informed that, "*detailed estimating and field verification has unearthed the need for increased scope of work to accommodate the new reactive facilities beyond what would normally be expected in a project of this scale*." Hydro One's *detailed estimate* terminology refers to AACE Class 3 estimates (-20% to +30%).

h) At the time of preparing the initial estimate, there were no site specific factors anticipated. The non-site specific factor related to the installation of shunt capacitor bank and reactor.

i) In the March 2019 letter to the OEB, details were provided on the new information that resulted in the cost variances. As noted in the letter, "*detailed estimating and field verification has unearthed the need for increased scope of work to accommodate the new reactive facilities beyond what would normally be expected in a project of this scale. Site specific conditions led to increased scope in the following areas: relocation of the existing low voltage capacitor bank, extension of the control building, increased grounding required, and increased cable trench / civil work.*"

j) Between the initial estimate and revised cost notification to the OEB, design work necessary to prepare detailed estimates was carried out. There were no procurement activities during this time.

k) Project scope for both the line and station remains unchanged and in line with IESOs requirements.

l) Please see response to part (i) above.

m) Hydro One developed the initial estimate with the understanding that Kapuskasing TS is an existing station but will have new facilities installed within the existing site.

n) Hydro One does not classify estimates as brownfield or greenfield. Estimates are developed based on the purpose required. Initial estimates would be of a preliminary or budgetary type and are developed based on a high level review of the site, review of cost of similar project, and input from staff. These estimates would be refined and accuracy improved as further detailed engineering is done and more information becomes known.

o) At the time of LTC Application, the line work was a detailed estimate, and station work estimate was preliminary in nature. The LTC Application was filed with the information available at the time due to the timing of the project to ensure sufficient time for the line work to be executed in order to satisfy the IESO's requested in-service date.

p) Hydro One would endeavor to submit detailed estimates as part of its LTC Application, provided that sufficient time is available between the IESO request and the specific need date.

OEB INTERROGATORY #137

Reference:
EB-2018-0098, Exh B/Tab 7/Sch 1/p2

Interrogatory:
At the above noted reference, Hydro One stated the following:

1.0 RISKS AND CONTINGENCIES
As with most projects, there are risks associated with estimating costs. Hydro One's cost estimate includes an allowance for contingencies in recognition of these risks. The top 3 project risks are outlined below. These risks are the major contributors to the total contingency suggested for this project.

- **Resource shortage –** there is a risk of resource shortages due to multiple projects that are set to be in execution at the same time in the general area of the KAR Project. This may lead to schedule delays and additional costs.
- **Outage constraints –** there is a risk that securing an outage will not be supported by customers in the area and this may result in schedule delays and additional costs.
- **Aggressive timelines** - there is a risk of not meeting the in-service date due to the aggressive timelines set on the Project (14 months following the leave to construct approval).

a) Were any of the top three project risks identified in the LTC application key drivers of the reactive and capacitive project component cost estimate variances? If yes, please explain in detail.

b) Was Hydro One aware when the LTC application was prepared that unknown construction complexities associated with a brownfield construction site were a potential project cost risk, even though not listed as one of the top three project cost risks, or should this risk be categorized as "Any other unforeseen and potentially significant event/occurrence" that was not included as a cost contingency "due to the unlikelihood or uncertainty of occurrence"?

Response:

a) No. The referenced top three project risks have already been accounted for in the contingency.

b) Hydro One was aware that this work would be completed at an existing transformer station, however it was assumed at that time that the new facilities could be installed at the station with assumptions and risks seen in other station projects. Hydro One did not foresee the complexities with this specific project, as documented in the correspondence to the OEB in March 2019.

OEB INTERROGATORY #138

Reference:
Ref: EB-2018-0098, Exh B/Tab 7/Sch 1/p. 3

Interrogatory:
At the above noted reference, Hydro One stated the following:

The comparable lines project, D2L Dymond x Upper Notch Junction was a line refurbishment project from Dymond TS to Upper Notch Jct Structure 261. The D2L Line Refurbishment included wood pole replacement, shieldwire replacement, like for like conductor replacement as well as line hardwares, dampers, u-bolts and insulators. The project went in-service in August of 2017. The main driver of the variance in comparable costs between the two projects is the number of wood pole replacements. H9K will replace 324 wood poles while D2L replaced 60 H-frame wood poles. Additionally, the H9K Project involves extra cost for multiple river crossings, access and terrain challenges such as swampy-like conditions.

a) Please explain why the "comparable projects" section of the LTC considers a project that primarily involved only line components.

b) In retrospect, was the selected comparable project an appropriate basis of comparison for a project for which the estimated cost of the station components exceeds the cost of the line components?

Response:
Hydro One notes that the Kapuskasing Area Reinforcement Project has already received OEB approval pursuant to Section 92 of the *OEB Act, 1998*. Alternatives to this Project to address the need identified by the IESO were already reviewed by the OEB in the Leave to Construct ("LTC") Application proceeding (EB-2018-0098).

a) Hydro One's requirement to install shunt reactive equipment of 10MVar is unique and no comparison estimate would serve as a direct comparison. High voltage shunt equipment typically installed on Hydro One's transmission system employ a much larger reactive rating, whereas lower MVar equipment is typically connected to the low voltage system and thus neither would serve as a direct comparison.

b) The comparison line project was appropriate for the line portion of this project. There was no appropriate comparison of a 10MVar rated high voltage connected shunt facility for direct comparison, as stated in response to part (a) above. Following completion of this project there will be comparison of this type of facilities for future investments.

OEB INTERROGATORY #139

Reference:
C-08-02

Interrogatory:
At the above noted reference, Hydro One stated the following:

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overhead costs supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year…

…In 2007, Hydro One Networks began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up to reflect actual results. This results in a better alignment of overhead costs with the capital projects that they support. Hydro One proposes that the overhead capitalization methodology, as reviewed in the B&V study in 2018, continues to be a reasonable method of distributing common corporate costs to capital projects. Hydro One's submissions in this Application reflect this overhead capitalization methodology.

At the above noted reference, Hydro One also provided a table (Table 1) that showed the forecast overhead capitalization rate is expected to decrease from 11% in 2019, to 10% in 2020 and 2021, and further to 9% in 2022. However, despite the declining trend in the overhead capitalization rate, the actual amounts capitalized are expected to increase from $114.1 in 2019 to $119.4 in 2020, to $122.6 in 2021, and $123.8 in 2022. As a result, the amounts capitalized have increased by $5.3 million or 4.6% between 2019 and 2020, whereas the overhead capitalization rate has decreased by 9.1% over the same period from a rate of 11% to 10%.

Hydro One also stated that "the capitalization rates are down relative to the previous transmission study mainly due to higher planned capital expenditures and lower OM&A."

a) Please explain why despite the declining trend in the overhead capitalization rate, the actual amounts capitalized are expected to increase.

b) Please update the table provided at the above noted reference with actuals from 2015 to 2018, as well as OEB approved 2017 and 2018, and explain any trends.

c) Please quantify and explain Hydro One's above noted statement that "the capitalization rates are down relative to the previous transmission study mainly due to higher planned capital expenditures and lower OM&A."

d) Please provide an overall explanation as to why there is an increased percentage of costs allocated to rate base in this proceeding versus the previous transmission proceeding.

Response:

a) The methodology for calculating capitalized overhead and capitalization rate is discussed in C-08-02-01.

The increase of capitalized overhead relative to 2019 is due to:

1. Higher capital expenditures during the plan period relative to small increases in overhead costs and OM&A. The methodology considers the work mix and would allocate more Corporate Cost to capital.
2. Slight increases in Corporate Costs.

The capitalization rate is decreasing due to the methodology; as it is specifically affected by the ratio of Corporate Costs (slight increase) to Capital spend (larger increase).

b) Please see C-08-02-02 for 2016-2018 Actuals for Overhead Expense and Capitalized OM&A. 2015 Actuals for Capitalized OM&A was $116.9M ($90.7M Admin and General, $26.2M Planning, Customer and Operating). Relative to 2015, the aggregate capitalization of overhead has been consistent however there has been a slight increase in capitalization of Admin and General costs and reduction in Planning, Customer and Operating costs. The change is largely due to method (described above) as well as the decrease in costs in 'Planning, Customer, and Operating costs' as a result of corporate reductions.

c) EB-2016-0160 Exhibit B1-03-10 Attachment 1 shows that Overhead Capitalization rates were assessed as 12.7% and 12.2% in the 2017 and 2018 years of the prior overhead capitalization study. The current study found in C-08-02-01 recommends an overhead capitalization rate of 9.7%. As 9.7% is lower than 12.2%, it can be concluded that Overhead Capitalization rates are down in the current study relative to the previous transmission study.

d) The overhead capitalized costs in this preceding are lower by approximately $16 million when comparing 2020 to the previously filed 2018 capitalization amount which is mainly due to a reduction in overall corporate overheads as discussed in F-02-01. These capitalized overhead amounts are not contributing to an increased rate base compared to the prior preceding. The rate base figure is increasing as a result of assets being placed in service as described in detail in Exhibit C, Tab 2, Schedule 1 which are based on capital investments as described in Sections 3.1 through 3.3 of the TSP.

OEB INTERROGATORY #140

Reference:
C-08-02

Interrogatory:
At the above reference, Hydro One discusses its methodology for capitalizing its overhead costs under US GAAP.

a) Over the term of this transmission rates application, please indicate how much more Hydro One is able to capitalize as a result of being on US GAAP compared to if it were following the OEB's MIFRS capitalization policy. If possible, please provide the analysis by year over the term of this application.

b) If a regulator were to order a utility to capitalize less for regulatory purposes than what is permitted under US GAAP, what implications would such a decision have on the US GAAP based financial statements?

c) In light of the fact that Hydro One reports into the Ontario government under IFRS for purposes of preparing the province's consolidate financial statements, has Hydro One considered moving to IFRS for its own financial statement reporting?

d) One of the main concerns that Hydro One raised in support of its transition to US GAAP was that IFRS did not allow for rate regulated accounting and therefore it would create significant volatility in its financial reporting. Now that IFRS does allow for rate regulated accounting and is in the process of developing a standard on regulated accounting, has Hydro One considered moving to IFRS?

Response:
Hydro One respectfully declines to answer these questions on the basis that they fall outside the scope of this proceeding and will be addressed as indicated by the OEB, either as part of an industry-wide policy review or at Hydro One's next rebasing application for both its distribution and transmission businesses (2023-2027).
In its Decision and Order in EB-2016-0160 at page 82, the OEB stated:

> *"Separate and apart from this proceeding, the OEB will consider whether it should initiate a policy review of the appropriateness of the continued use by the utilities it regulates of USGAAP for the purpose of determining the capitalization of overhead amounts."*

In its Decision and Order in EB-2017-0049 dated March 7, 2019 in Appendix 2, the OEB directed Hydro One to file a report on its capitalization of common corporate costs as part of its next rebasing application:

> *"Filing of a report as part of its next rebasing application that compares Hydro One's capitalization of common corporate costs with those of other utilities in Ontario, Canada and North America. This should include utilities both under US GAAP and those using International Financial Reporting Standard (IFRS). Hydro One may need to disaggregate its corporate costs into separate cost elements in order to do an appropriate comparison."*

Given the OEB's direction on this topic, questions in respect of Hydro One's capitalization of common corporate costs should be addressed in one of the two proceedings-types noted by the OEB above, where the appropriate evidence may be prepared and submitted for consideration.

OEB INTERROGATORY #141

Reference:
C-08-02

Interrogatory:
At the above noted reference, Hydro One stated the following:

…Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in Hydro One's industry research of other Canadian and US utilities.

a) Please provide an analysis which shows that Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs and also as percentage of capital, is within the observed range and consistent with the median found in Hydro One's industry research.

Response:
a) The context of this statement was describing the results of the review filed with the OEB at part of Hydro One's 2013-2014 rate application (EB-2012-0031). Please see Exhibit C, Tab 8, Schedule 2 page 3 lines 5-22 for the full reference to the above mentioned review. Hydro One will be updating this study as part of its next rebasing application as directed by the OEB in the EB-2017-0049 decision. Additional details that describe Hydro One's capitalization methodology and review by Black and Veatch are provided in Exhibit C, Tab 8, Schedule 2 Attachment 1.

OEB INTERROGATORY #142

Reference:
C-08-02-02, C-08-02

Interrogatory:
At the above noted first reference, Hydro One showed an overhead capitalization rate of 24% for 2019 and 2020. However, at the second reference overhead capitalization rates of 11% and 10% are shown respectively for 2019 and 2020.

a) Please explain the different overhead capitalization rates that are shown for 2019 and 2020

Response:
a) The data point referenced in C-08-02-02 is a percentage of OM&A that was capitalized relative to Total OM&A before Capitalization.

   C-08-02 discusses the Overhead Capitalization Rate calculated by the methodology reviewed by Black and Veatch. The data points referenced in C-08-02 are the expected Overhead Capitalization rates. Appendix 1 of the above mentioned exhibit provides further detail of the Black and Veatch study. The Overhead Capitalization rate is applied as a percentage to all capital spend as a mechanism for allocating (recovering) capitalized overheads. The rate is evaluated throughout the year to ensure consistency with capitalizing overhead as calculated by the Black and Veatch methodology.

OEB INTERROGATORY #143

Reference:

C-08-02-01, F-02-06-01, C-03-01-01

Interrogatory:

a) Please state how the above noted studies in the current application relate to the studies filed in the previous Transmission application and Distribution application.

b) Please provide a table summarizing and comparing the key recommendations of the current studies with those in the previous studies. Please include an explanation for any changes between the recommendations in the current studies and those in the previous applications. Please describe whether and how any changes were made that would materially impact the 2020 test year revenue requirement.

Response:

Note: Previous Transmission application is the 2017/18 Tx application EB-2016-0160
Note: Previous Distribution application is the 2018-2022 Dx application EB-2017-0049

a) Reference C-08-02-01 above refers to *Review of Overhead Capitalization Rates* study. Key differences in the current application, relative to the previous Transmission & Distribution applications:
   1. Accountability Act & Executive labour cost assignment – the requirement to directly assign certain executive labour costs to shareholders resulted in a model that is no longer purely cost-causative. The rationale to directly assign these costs to shareholders was not based on cost-causative principles but rather was done to meet the requirements of The Act. Black & Veatch believes that the current cost allocation methodology continues to be appropriate for Hydro One, because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent, regulatory practice, and now legislative compliance), and promotes transparency and efficiency.
   2. Refreshed time study – Both previous applications were based on the 2015 time study. Labour costs assigned between OMA/Capital/Distribution/Transmission in the current 2020 – 2022 Tx application is based on the 2017 time study performed for the four-week period ending June 9, 2017. The methodology was the same as used in prior time studies conducted by Black & Veatch for Hydro One. Black &

Veatch found that the 2017 Time Study was properly conducted, and therefore is a proper basis to determine the portion of the costs of the participating departments to be capitalized and allocated to Transmission.

Reference F-02-06-01 refers to *Review of Allocation of Common Corporate Costs* study. Two key differences in the current application, relative to the previous Transmission and Distribution applications:

1. Accountability Act & Executive labour cost assignment – the requirement to directly assign certain executive labour costs to shareholders resulted in a model that is no longer purely cost-causative. The rationale to directly assign these costs to shareholders was not based on cost-causative principles but rather was done to meet the requirements of The Act. Black & Veatch believes that the current cost allocation methodology continues to be appropriate for Hydro One, because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent, regulatory practice, and now legislative compliance), and promotes transparency and efficiency.

2. Refreshed time study – Both previous applications were based on the 2015 time study. Labour costs assigned between OMA/Capital/Distribution/Transmission in the current 2020 – 2022 Tx application is based on the 2017 time study performed for the four-week period ending June 9, 2017. The methodology was the same as used in prior time studies conducted by Black & Veatch for Hydro One. Black & Veatch found that the 2017 Time Study was properly conducted, and therefore is a proper basis to determine the portion of the costs of the participating departments to be capitalized and allocated to Transmission.

Reference C-03-01-01 refers to *Review of Shared Assets Allocation* study. The shared assets and their allocation are unaffected by any of the direct assignments made in the Common Corporate Cost Model to comply with the Hydro One Accountability Act. The two key streams in this report and related differences within each are:

1. Allocation of Asset Costs to Transmission and Distribution:
   In its 2020-2022 Transmission Rates filing, Hydro One has allocated 38.3% of the cost of the Shared Assets to its Transmission business and 61.7% to its Distribution business. These ratios are slightly different than the ratios used in its previous Transmission and Distribution Rate filings due to large investments in software solely relating to the distribution business.

2. Development of Transfer Price Charge Rates for Telecom and Remotes: Consistent application of methodology in line with previous Transmission and Distribution applications.

b) No key recommendations are noted for implementation between the studies. As noted in Part a) there have been no material differences between the studies and Black and Veatch believe that the current methodology continues to be appropriate for Hydro One.

OEB INTERROGATORY #144

Reference:
C-08-02-01, F-04-01-05

Interrogatory:
At the above noted first reference, the following is stated:

Approximately $89 million of labour costs, representing approximately 33% of the annual total Common Corporate Costs (and approximately 42% of annual labour costs), were directly assigned between OMA and capital based on a time study performed for the four-week period ending June 9, 2017 (“2017 Time Study”)…

At the above noted second reference, total compensation costs from 2014 to 2022 are quantified.

a) Please state whether or not the labour costs allocation in the first reference was incorporated into the total compensation costs shown in the first reference. If not, please explain.

Response:
a) The total compensation costs shown in the second reference (F-04-01-05) represent all labour costs including the allocation of corporate labour costs subject to time study in the first reference (C-08-02-01).

OEB INTERROGATORY #145

Reference:

D-02-01

Interrogatory:

a) Please compare the above referenced two tables to each other and discuss how the measures in both tables compare to each other and the extent to which the measures and the corresponding description are the same, similar or different?
   i. If they are the same or similar, please explain any differences in the descriptions between the two tables,
   ii. If they are different, why would the measure of reliability performance outlined in Exhibit D not be on the scorecard in the TSP?

Response:

a)
   i. They are generally the same.
      - "Frequency of Delivery Point Interruptions" in Table 1 in Exh D/ Tab 2/ Sch 1 – Section 1.2 is the sum of sustained and momentary interruption frequency or "T-SAIFI-S" and "T-SAIFI-M" respectively as provided in Table 2 in Exh B/Tab 1/Sch 1/TSP Section 1.5.2.
      - "Duration of Delivery Point Interruptions" in Table 1 in Exh D/ Tab 2/ Sch 1 – Section 1.2 is the same as "T-SAIDI" in Table 2 in Exh B/Tab 1/Sch 1/TSP Section 1.5.2.
      - "Transmission Equipment Unavailability" in Table 1 in Exh D/ Tab 2/ Sch 1 – Section 1.2 is the same as "System Unavailability" in Table 2 in Exh B/Tab 1/Sch 1/TSP Section 1.5.2.
      - "Delivery Point Unreliability Index" in Table 1 in Exh D/ Tab 2/ Sch 1 – Section 1.2 is the same as "Unsupplied Energy" in Table 2 in Exh B/Tab 1/Sch 1/TSP Section 1.5.2.

   ii. They are same.

Witness: Bruno Jesus

OEB INTERROGATORY #146

Reference:
D-02-01

Interrogatory:
At the above reference, it is stated that:

Hydro One's comparative reliability performance at the system level is illustrated in the following Figures:

- Figure 1a - frequency of momentary interruptions;
- Figure 1b - frequency of sustained interruptions;
- Figure 2 - overall frequency of interruptions;
- Figure 3 - average duration of sustained interruptions; and
- Figure 4 - delivery point unreliability index.

a) Please state whether or not these figures correspond with the measures proposed in Exhibit D/ Tab 2/ Sch 1- Section 1.2: Transmission Reliability Measures, Table 1: Transmission Reliability Measures or Exhibit B-1-1/ TSP Sec 1.5.2- Performance Measurement Methods and Measures, Table 2- Operational Effectiveness Measures.
   i. If they do correspond, please explain any differences in their descriptions.

Response:
a) The measures in these figures are described in Table 2 of Exhibit B-1-1, TSP Section 1.5.2. These measures correspond with the measures proposed in Table 1 of Exhibit D, Tab 2, Schedule 1- Section 1.2.
   i. Please refer to the answers in I-01-OEB-145.

OEB INTERROGATORY #147

Reference:
D-02-01

Interrogatory:
OEB staff notes that in Figure 5, the CEA 5 Year Moving Average indicates a downward trend (improving) starting in 2012. However Hydro One's Unavailability of Transmission Lines has been trending upwards (worsening) starting 2014.

a) Please explain the upward trend.

b) Please discuss Hydro One's plan to reduce Unavailability of Transmission Lines to the CEA level or below.

c) Please explain the 190% increase from 2017 to 2018.

Response:
a) The trends illustrated in Figures 5 and 6 of D-02-01 are primarily due to:
   - An oil leak and repair on L16D in 2015.
   - A downed conductor on A6R in 2015.
   - A faulted cable section on HL4 in 2016.
   - A downed tower impacting H22D and L20D in 2016.
   - A joint failure on H11L, described in TSP 2.2, page 63, impacting 2016, 2017 and 2018.

   Lengthy outages were needed to safety perform quality and long-lasting repairs, and complete the necessary environmental remediation associated oil leaks.

b) Hydro One's objective is to address EOL assets before the pose a reliability risk and we will continue to do so. Generally, Hydro One's transmission line unviability has been under the CEA composite 5-year moving average. In 2016 and 2017 there were numerous one-off outages primarily caused by external factors contributing to transmission lines unavailability as described in part (a).

Witness: Bruno Jesus

c) Outages in 2018 were primarily related to a small number of lengthy circuit outages mainly driven by external factors:

- C7BM – 2134 hours - Circuit damaged during Ottawa area tornados
- A5RK – 1071 hours – Cable damaged due to third-party excavation
- H11L – 1020 hours – Joint failure and subsequent repair, described in TSP 2.2, page 63
- A3M – 362 hours – Fire under line burned transfer trip communications owned by Bell.

OEB INTERROGATORY #148

Reference:
D-02-01

Interrogatory:
In Figure 6, the CEA 5 Year Moving Average indicates a downward trend (improving) starting in 2012. However Hydro One's Unavailability of Major Transmission Station Equipment has been trending upwards (worsening) starting 2013, and is currently 60+% above CEA 5 Year Moving Average from 2015 – 2017.

a) Please explain the upward trend.

b) Please discuss Hydro One's plan to reduce Unavailability of Major Transmission Station Equipment to CEA Composite level or below.

c) Please explain the 41% increase from 2017 to 2018.

Response:
a) The trend has been driven primarily due to longer outages on high voltage capacitors, reactors and high voltage capacitor breakers.

b) As per TSP-02-02 pg 13 of 117, Hydro One's plan for its transformer fleet over the next five years has been influenced by fleet demographics, observed conditions, anticipated conditions, and performance factors as well as environmental and safety concerns. The plan aims to sustain the transformer fleet via maintenance and replacements. Pg 22 of 117, Hydro One's plan for the breaker fleet over the next five years has been influenced by the demographic, condition, performance, vendor support, air leak, PCB factors described above and health and safety concerns. The plan aims to employ maintenance and replacements in order to maintain fleet performance. Hydro One plans to replace on average 128 breakers annually from 2020 to 2024. The approach is to target specific breaker populations to deal with system risks, and steadily pace investments driven by obsolescence caused by reduced vendor support for aged product lines. However this recent increase in unavailability trend, as indicated above, occurred as a result of unavailability of some capacitor breakers, reactor, and capacitors. Due to available redundancy and low demand for capacitive support the work on capacitor breakers and capacitors had been reprioritized in order to address the need of more critical assets. There are three breakers showing major contribution to the unavailability and two have already been addressed recently and one is being replaced in near future. There is also one reactor which has been out of service for more than two years. This unit is being replaced by the end 2019 or early 2020. There are also five capacitor banks with significant contribution to unavailability. Two of which are already addressed and the remainder of banks will be prioritized and addressed.

c) Year over year increase primarily driven by increased duration of outages on high voltage capacitors, reactors and high voltage capacitor breakers in addition to some extended outages for retirement/replacement.

OEB INTERROGATORY #149

Reference:
E-01-01

Interrogatory:
a) Please provide a version of this table with the missing information for 2019: OM&A, Depreciation and Amortization, Income taxes, Return on Capital.

b) Please include with the revised version of this table the reference exhibits for the components listed in Note 3: External Revenue and other: i.e. External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit.

Response:
a) The 2019 OEB approved revenue requirement in EB-2018-0130 was derived using the OEB proposed calculation in the Decision and Order issued on April 25, 2019 and confirmed as part of the final Decision and Rate Order issued on June 13, 2019. The derivation of 2019 OEB approved Base Revenue Requirement was done by escalating the 2018 OEB approved Base Revenue Requirement (excluding Bill 2 impact) by 1.4% while maintaining 2019 Revenue Offsets (External Revenue, WMS Revenue, and Export Tx Service Revenue) at 2018 levels. As a result, a specific breakdown by component was not approved and cannot be provided.

b) Please see the revised version of the table to include the breakdown for External Revenue and Other:

Table 1: Revenue Requirement ($ Millions)

Components	2018[1]	2019[2]	2020	Reference
OM&A	394.3		375.8	Exhibit F, Tab 1, Schedule1
Depreciation and Amortization	468.6		474.6	Exhibit F, Tab 6, Schedule 1
Income Taxes	57.2		48.3	Exhibit F, Tab 7, Schedule 2, Attachment 1
Return on Capital	703.6		775.0	Exhibit G, Tab 1, Schedule 1
Total Revenue Requirement	**1,623.8**	**1,644.4**	**1,673.8**	
Deduct External Revenues	(28.5)	(28.5)	(31.4)	Exhibit E, Tab 2, Schedule1
Deduct Export Tx Service Revenue	(40.1)	(40.1)	(35.9)	Exhibit I2, Tab 4, Schedule 1
Deduct MSP Revenue	(0.3)	(0.3)	(0.1)	Exhibit I2, Tab 3, Schedule 1
Low Voltage Switch Gear Credit	14.1	14.3	14.8	Exhibit I1, Tab 1, Schedule 3
Rates Revenue Requirement	**1,569.1**	**1,589.9**	**1,621.2**	
Regulatory Deferral and Variance Accounts Disposition / Foregone Revenue	(58.4)	(37.6)	6.8	Exhibit H, Tab 1, Schedule 3
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,510.7**	**1,552.3**	**1,628.0**	

Note 1: Represents OEB approved 2018 revenue requirement from Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160
Note 2: Represents OEB approved 2019 revenue requirement in EB-2018-0130

OEB INTERROGATORY #150

Reference:
E-02-01 Table 1
EB-2016-0160 E1-02-01 Table 1

Interrogatory:

a) Please reconcile the two 2015 Historic Secondary Land use numbers and Other External Revenues and identify the correct amount. Please provide an explanation for the change.

b) OEB staff notes that historically, external revenue has been under forecasted (i.e. 2016- 51% variance; 2017- 26% variance, 2018- 38% forecasted variance). Please explain the large variances between the forecasted and historical external revenues and discuss whether or not Hydro One is looking into a more accurate forecast methodology for external revenues.

Response:

a)

2015, $ millions	EB-2016-0160 (2016.07.20)	EB-2019-0082 (2019.06.19)	Var
Secondary Land Use	$31.6	$34.3	$2.7
Other External Revenues	$12.8	$10.1	-$2.7

The previous 2015 figure submitted for Secondary Land Use was $31.6M and this was corrected to $34.3M to reflect a re-classification from Other External Revenues to Secondary Land Use.

The table below provides the breakdown of the delta and the revenue that is Secondary Land Use.

Project	Dollars ($M)
ADMIN FEES REVENUE	(0.5)
COMMERCIAL REVENUE	(1.0)
MISC LUMP SUM PAYMENTS REVENUE	(0.1)
MISC RENTAL REVENUE	(1.1)
Total	(2.7)

b) The external revenue variances have been primarily driven by Secondary Land Use, which is difficult to forecast beyond a one-year time frame with a level of certainty. Please refer to Exhibit I, Tab 10, Schedule VECC-019, part b) for additional details regarding forecasting.

Hydro One could not recreate the percentage variance in the above question for 2016, and provides a summary of the forecast and historical actual external revenues below.

$M	2016	2017	2018
EB-2016-0160 (2016.07.20), Forecast	28.8	28.2	28.5
EB-2019-0082 (2019.06.19), Actuals	42.3	35.5	39.4
% variance	**47%**	**26%**	**38%**

OEB INTERROGATORY #151

Reference:
EB-2017-0049 Decision and Order p.129

Interrogatory:
The OEB findings at the above reference “require Hydro One to do further investigation on the use of weather data from multiple locations in the province”.

Please provide an update as to the status of this investigation.

Response:
As detailed in Exhibit E, Tab 3, Schedule 1 pages 11-12, Hydro One does use weather data from multiple locations in the province in developing its transmission delivery point forecast in this Application as well as previous Transmission Applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, and EB-2016-0160).

Hydro One’s investigation on the use of weather data for the transmission system is as follows. Hydro One considered the statistical performance of Toronto Pearson International (“Toronto”) weather data versus the average weather data across five weather stations in Ontario (Windsor, Thunder Bay, Toronto, North Bay, and Ottawa), “average” for short, in the context of sectorial econometric models that have weather variable as explanatory variables, as follows:

Residential Model
The estimated model based on the average weather data is:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.056096	0.016242	-3.453752	0.0008
C(2)	0.152072	0.043924	3.462159	0.0008
C(3)	0.628397	0.126587	4.964145	0
C(4)	0.283781	0.120242	2.360084	0.0204
C(5)	-0.039921	0.021169	-1.885857	0.0625
C(6)	-0.03076	0.016792	-1.831835	0.0702
C(7)	0.110571	0.059271	1.865519	0.0653
C(8)	0.074699	0.049925	1.496231	0.1381

Witness: Henry Andre

C(9)	-1.037756	0.261604	-3.966895	0.0001
C(10)	0.947097	0.251731	3.762344	0.0003
C(11)	-0.001682	0.000516	-3.262419	0.0016

Saturation Model Fit:

R-squared = 0.96, Adjusted R-squared = 0.96, Durbin-Watson = 2.10

Usage Model Fit:

R-squared = 0.95, Adjusted R-squared = 0.94, Durbin-Watson = 1.87

It can be observed that the t-statistics for coefficient C(8) which involves weather variable is 1.50, which is not statistically significant at 10% significance. The corresponding t-statistics in the model used in this Application based on Toronto weather data is 1.85, as shown in Exhibit E, Tab 3, Schedule 1 Appendix B, which is statistically significant at 10% significance. It can also be observed that, overall; the majority of the t-statistics of coefficients in the estimated model are lower in absolute value compared to the latter. Accordingly, the use of Toronto weather data in the residential equation out-performs the average weather data in that it yields statistically more significant estimates.

Transportation Model

The estimated model based on the average weather data is:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	1.269454	0.575806	2.204656	0.0359
C(2)	0.784745	0.087326	8.986347	0
C(3)	-1.37E-06	1.04E-06	-1.314186	0.1994
C(4)	0.182978	0.064848	2.821662	0.0087
C(5)	0.000742	0.000231	3.214326	0.0033
C(6)	-0.537169	0.096528	-5.564892	0
C(7)	0.336872	0.093151	3.616408	0.0012

Model Fit:

R-squared = 0.849, Adjusted R-squared = 0.816, Durbin-Watson = 2.22

It can be observed that the t-statistics for coefficient C(5) with involves weather variable, is 3.21, which is statistically significant at 5% significance or lower. The corresponding t-statistics in the model used in this Application using Toronto weather data is 3.35, as shown in Exhibit E, Tab 3, Schedule 1 Appendix B, which is also statistically significant at 5% significance or lower. It can also be observed that the t-statistics for most of the other coefficients in the estimated model are lower in absolute value compared to the model used in this Application. Accordingly, the use of Toronto weather data in the transportation equation out-performs the average weather data in that it yields statistically more significant estimates.

Commercial Model

The estimated model based on the average weather data is:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.018647	0.005777	-3.227587	0.0023
C(2)	0.073941	0.02224	3.324657	0.0017
C(3)	0.898014	0.024266	37.00669	0
C(4)	0.03033	0.013843	2.19101	0.0334
C(5)	0.218513	0.120852	1.808109	0.077

Saturation Model Fit:

R-squared = 0.998, Adjusted R-squared = 0.998, Durbin-Watson = 2.03

It can be observed that the t-statistics for coefficient C(4) with involves weather variable, is 2.19, which is statistically significant at 5% significance or lower. The corresponding t-statistics in the model used in this Application is 2.22, as shown in Exhibit E, Tab 3, Schedule 1 Appendix B, which is also statistically significant at 5% significance or lower. It can also be observed that, overall; the majority of the t-statistics of coefficients in the estimated model are lower in absolute value compared to the latter. Accordingly, the use of Toronto weather data in the commercial equation out-performs the average weather data

In short, in all the cases examined, Toronto weather data out-performed the average weather in that it yields statistically more significant estimates. Accordingly, the Toronto data was used in this Application.

OEB INTERROGATORY #152

Reference:
E-03-01 Appendix B
EB-2016-0160 E1-03-01

Interrogatory:

a) Please identify and explain any updated variables in the annual econometric models at the above references.

b) Please discuss the references to the use of National Energy Board (NEB) forecasts in the current application as these do not appear to have been used in the previous application. Please confirm that this is a change from the previous application and discuss why it was made.

c) Please discuss how the model used in the current application compares to that used in the previous application and to what extent it provides an improved forecast.

Response:

a) In Exhibit E, Tab 3, Schedule 1 Appendix B, all variables were updated to include latest information. Other changes made between this Application and evidence in EB-2016-0160 is as follows.

1. **Residential Model, Saturation (LELSAT) Equation:**
   - Cross-price variable LPLIQRES was deleted from the model because it was not statistically significant. Its t-statistic was only 0.17 which is much lower that the corresponding figure (1.09) in EB-2016-0160/Exhibit E1-3-1.

2. **Residential Model, Usage (LEUSE) Equation:**
   - Instead of using own-price (LPELRES) and cross-price (LPLIQRES) variables separately (as in EB-2016-0160/Exhibit E1-3-1), the difference in these variables was used to reflect relative prices explicitly. Moreover, the former formulation led to wrong sign for the cross-price variable.
   - For the weather variable (LHDD) a new functional form (LHDD^b) was used in the current Application. A range of values for the exponent ‘b’ was tried including (1, 0.75, 0.5, and 0.25) and the best case was found to be 0.5 in

terms of statistical significance, with the corresponding t-statistics being (1.14, 1.75, 1.85, and 1.81).

- A trend variable (TR3) was added to the model as it was statistically significant, as show on page 32 in Exhibit E, Tab 3, Schedule 1 Appendix B.

3. Commercial Model:

- In place of own-price (LPELCOM) and its lag in EB-2016-0160/Exhibit E1-3-1, difference between the own and cross-price (LPGASCOM) variables are used in this Application. Moreover, it was assumed that such relative price impact on commercial load would depend on commercial electricity intensity (ELCOM/GDPCOM) before the year 2007, when the Conservation and Demand Management ("CDM") started in Ontario. Thus, the higher the electricity intensity, the higher is the impact of relative price of elasticity in absolute value as it makes it more worthwhile to respond to the relative price changes before the start of CDM initiatives.
- Different combinations of weather variables (LCDD and LHDD) and lagged dependent (LELCOM) variables was tried and the best combination in terms of regression criteria was found to be using LCDD, one period lag of LELCOM and change in the one-period lag of LELCOM. For example, adding the latter variable to model improved Durbin Watson statistic from 1.5 to 2.0. Also the t-statistic for LHDD was very low (0.46) when that variable was included in the model and, the t-statistic for change in the one-period lag of LELCOM dropped to 1.64. Since the latter t-statistic was much higher than the one for LHDD, LHDD was deleted from the model.

4. Industrial Model (ENEQ) Equation:

- The lag structure of total energy price (PENIND) was changed from average of current and one-period lag average to current and eight-period lag average, based on statistical significance of the estimated price elasticity. The t-statistic for 1 to 9 period lags were (-1.46, -1.44, -1.51, -1.51, -1.61, -1.79, -1.79, -2.16 and -1.64) of which 2.16 is the highest in absolute value corresponding to the current and eight-period lag average and so this variable was used.
- A dummy variable (D13), which equals 1 in 2013 and 0 elsewhere, was added to the model for this Application due to its statistical significance to pick up a transitory change in load in that year.

5. Industrial Model, Energy Share (LW13 and LW23) Equation:

- No change in variables.

6. Agricultural Model:

- In EB-2016-0160/Exhibit E1-3-1, change in personal disposable income (LYPD) lagged three-periods was used to link demand for electricity in agricultural sector to income as the scale variable. The t-statistic with this variable was only 0.24 reflecting its lack of statistical significance but the estimate had correct (positive) sign. When this variable was tried in the current Application it had a wrong (negative) sign and continued to be statistically insignificant with the t-ratio of -0.76. After examining alternative scale variables with correct sign, change in Ontario population (POPONT) with four-period lag was selected. With a t-statistic of 1.48, it is statistically not significant at 10% significance but is so at nearly 15%.
- Similarly, when the relative price variable (PELRES/(PLIQRES) was tried, it was not statistically significant as in EB-2016-0160/Exhibit E1-3-1 with even a lower t-statistic in absolute value (-1.33 vs. -0.99). Accordingly, this variable was deleted from the model.

Overall, these developments suggest that the demand for electricity in agricultural sector depend on long term trends such as Ontario population, and cyclical variables. This result is consistent with agricultural sector producing nondiscretionary commodities.

7. Transportation Model:

- In EB-2016-0160/Exhibit E1-3-1, the average of current and lagged values of electricity price during the last three years was used as the price variable. In the current Application, relative price of electricity (LPELRES – LPGASRES) was used due to its better statistical significance (with t-statistic being 8.64 vs. -1.68). This implies that a higher relative price (or: price margin) of electricity corresponds to a higher supply of electricity by gas-fired generators and that, in turn, requires natural gas companies to use more electricity to transport /pump natural gas. Thus, supply considerations on the part of generators outweigh cost considerations on the part of gas companies in this regard.
- In EB-2016-0160/Exhibit E1-3-1, dummy variables D98ON and D0812 were used to pick up structural change and outliers, with corresponding t-statistics

being 2.05 and -9.87, respectively. In this Application, dummy variables D0708 and D98 were found to be more relevant, with t-statistics being 2.95 and 3.70. When the earlier variables (D98ON and D0812) were added back to the model, they both had statistically insignificant t-statistic (1.64, 0.46 respectively).

b) Use of National Energy Board ("NEB") energy prices in this Application was due to availability of recent information from the NEB 2018 database. The only exception in this regard was the price of coal for Ontario industrial sector, for which NEB did not have a forecast. In this case, Hydro One used the forecast provided by IHS Global Insight. In EB-2016-0160/Exhibit E1-3-1 this information from a single source was unavailable, so Hydro One had to produce a forecast for energy prices based on most recent information from multiple sources. The use of the NEB energy prices is in line with Hydro One practice in the past proceedings to use the most up-to-date information as well as aligns with OEB direction on page 68 in EB-2016-0160 Decision and Order (dated October 11, 2017), regarding energy prices.

c) In each Application, Hydro One starts with the forecasting models used in the last approved filing and then examines the possibility of improving the models. For the current Application, the starting (default) forecasting models were those in EB-2016-0160/Exhibit E1-3-1 and, as discussed in response to part (a) above, various changes to those models were found to be needed to account for the recent information. However, two fundamentals remain unchanged. First, the economic theory underlying the models has not changed, e.g., consistency with consumption theory. Second, the econometric structure of the model has not changed, e.g., share model used to derive demand for different energy types in the industrial sector. Thus, the only changes are of a practical nature, such as the number of lags for explanatory variables, selecting between different measure of scale factor in consumption equations (e.g., income, population, etc.), and use of dummy variables to address structural changes and outliers. The changes made to the models result in improved load forecast accuracy, as demonstrated in the response to Exhibit I, Tab 1, Schedule OEB-153.

OEB INTERROGATORY #153

Reference:

E-03-01 Appendix F
EB-2016-0160 E1-03-01

Interrogatory:

Please state whether or not the revised model been retroactively applied and a study completed to determine the accuracy of the proposed models and previous models when compared to the historical actuals?

Response:

Yes, two sets of sectorial models - the one in the current Application (2018 Model) and the one from the previous Application EB-2016-0160/Exhibit E1-3-1 (2016 Model) – were retroactively applied to forecast the load for the years 2015 and 2016 for which actual load were readily available so that the forecast error could be calculated. The results from the two models are provided below in terms of Root Mean Squared Error ("RMSE") and %RMSE of the forecast. There was no change in monthly econometric model and, therefore, it is not included in this comparison.

Measurement	2016 Model	2018 Model
RMSE (GWh)	4,826	791
%RMSE	3.57%	0.59%

The results show that the forecast error, using either RMSE measurement, is smaller for the 2018 Model compared to the 2016 Model.

Witness: Bijan Alagheband

OEB INTERROGATORY #154

Reference:

F-01-03
(1) p.41
(2) p.40
(3) EB-2016-0032, Notice of Proposal to Amend a Code, Dec 20, 2017, p.13

Interrogatory:

At the first reference above, it is stated that:

Hydro One's overall planned expenditures for Cyber Security Management in the 2020 Test Year are $15.6 million, which is lower compared to the 2015-2018 historical period. This funding is required for the continued maintenance of cyber security assets, conducting annual surveys, and managing, operating and monitoring cyber security systems described above. Increased spending in 2015 and 2016 was a result of efforts to achieve compliance with NERC CIP V5.

At the second reference above, it is stated that:

Compliance with NERC CIP Version 5 ("V5"), which applied to Hydro One's High and Medium voltage transmission systems, increased the cyber security sustainment program by introducing new processes and procedures, many of which must be tested at least every 15 months. Compliance with NERC CIP Version 6 ("V6") extends requirements to Hydro One's Low impact classified sites requiring both physical and electronic access controls. NERC CIP V6 brought into scope approximately 60 additional facilities which were not part of the NERC CIP V5 compliance program. The proposed next generation of NERC CIP Version 7 ("V7") Standards is in the final drafting stages and includes inter-control center communication and virtualization. These standards are expected to be approved with compliance due dates in the 2019-2021 timeframe.

At the third reference above, it is stated that:

…The OEB believes that transmitters and distributors should have already incorporated cyber security into their business and asset planning, consistent with their risk portfolio…

The first reference suggests that costs will be lower in the 2020 Test Year than the 2015-2018 historical period because of increased spending in 2015 and 2016 as a result of efforts to achieve compliance with NREC CIP V5.

The second reference would suggest that in the Test Year period costs to achieve compliance with V5 will continue and there will also be additional costs related to V6 and V7.

a) Given the above, please explain why Hydro One believes it is reasonable to assume that expenditures on cyber security costs in the Test Year will be lower than they were in the 2015-2016 period.

b) Please explain why Hydro One is seeking incremental costs for cyber security in OM&A when as noted above, transmitters should have already incorporated cyber security into their business and asset planning.

Response:

a) Expenditures on cyber security in the Test Year are lower than they were in the 2015-2016 period because during the 2015-2016 period, Hydro One was required to increase costs to achieve compliance with the NERC CIP V5 standard. The subsequent changes introduced in V6 and V7 are minor in comparison to the changes introduced in V5. Consequently, the costs are expected to be lower in the Test Year.

b) EB-2016-0032, Notice of Proposal to Amend a Code, Dec 20, 2017, p.13 only applies to the parts of the power system that the NERC CIP standard does not cover (Non-Bulk Power System transmission and distribution). The incremental costs Hydro One is seeking for cyber security is only for the new NERC CIP standards (V6 and V7).

OEB INTERROGATORY #155

Reference:

F-01-03 p.47

EB-2017-0049 Q-01-01 p.12-13

Interrogatory:

At the first reference above, Hydro One's approach to vegetation management in the current application is discussed.

At the second reference above, which is an update filed in December 2017 from Hydro One's recent distribution rates application, Hydro One's new vegetation management strategy is discussed and it is stated that:

Since the Application was filed, Hydro One has continued to further explore opportunities for continuous improvement in vegetation management and innovative approaches working with Clear Path Utility Solutions LLC. ("Clear Path"), an expert in utility vegetation management. A quantitative workload study was conducted by Clear Path which measured Hydro One's maintenance backlog and future workloads and recommended a vegetation management strategy designed to improve the condition and reliability of Hydro One's right-of-ways….

Based on Clear Path's recommendations, Hydro One has developed a new vegetation management strategy that maintains corridors on a three-year cycle, focusing on defects rather than completely clearing vegetation in a corridor. This defect-based approach will address vegetation that poses a public safety or reliability threat because it is either (a) growing into or will grow into energized equipment within the three-year maintenance cycle, and/or (b) dead/dying vegetation that will likely cause system interruption and/or equipment damage within the maintenance cycle.

a) Please discuss how Clear Path's study has impacted the current application.

Response:

a) Clear Path's study refers to Hydro One's Distribution Vegetation Management Program and is not applicable to the Transmission Vegetation Management Program discussed in this Application.

Witness: Donna Jablonsky

OEB INTERROGATORY #156

Reference:
F-01-03 p.10 Table 3

Interrogatory:
The above referenced table provides Hydro One's environmental management OM&A which is shown as increasing from $16.7 million in 2017 to $22.1 million in the 2020 Test Year, representing an increase of $5.4 million or 33%.

OEB staff notes that this overall increase is made up of significant increases in the categories of "PCB Retirement and Waste Management" and "Environmental Compliance and Emergency Response Plan Updates", offset by significant decreases in the other two categories of "Transformer Oil Leak Reduction" and "Preventative and Corrective Maintenance."

a) Please discuss the extent, if any, to which the cuts in spending in the latter two categories are related to the increases in the former two categories.

b) Please discuss whether or not the reduced spending levels in the two categories with reduced spending are considered to be sustainable, or one-time in nature.

Response:
a) PCB retirement and Waste Management relates to retro filling PCB filled assets. Some of these assets are also candidates for Transformer Oil leak reduction work. Bundling this work together has helped to lower the OM&A cost for leak reduction work. Otherwise the referenced categories of work are completely different programs.

b) Expenditures in the "Preventative and Corrective Maintenance" category for the 2020 Test year are in line with 2019 expenditures. Spending in both categories are sufficient to ensure compliance with MOECP requirements and to meet corporate Environmental Policy objectives.

OEB INTERROGATORY #157

Reference:

F-01-03 p.11

Interrogatory:

At the above reference, it is stated that:

However, to manage its OM&A spending, in 2019, Hydro One deferred a planned increase to its PCB program, which resulted in a reduced buffer period to comply with the Environment Canada deadline. Hydro One anticipates completing the required PCB remediation by 2024, which is one year later than previously planned, but which leaves only a one-year buffer period for completion of the work within the required timeframe.

a) Please state whether or not the deferred planned increase to Hydro One's PCB program to manage OM&A spending in 2019 was entirely incorporated into the 2020 spending or was spread over the anticipated spending on this program in the 2020 to 2024 period on an equal basis.

b) Please describe the impact on the 2020 test year revenue requirement, including the impacts on both 2020 OM&A and 2020 capital, if the one-year buffer period is eliminated and Hydro One completes this work in 2025, instead of completing by 2024. Please explain the associated risks of deferring this work further to 2025.

Response:

a) The deferred planned increased was spread equally across the 2020-2024 period.

b) If the work was completed in 2025 and the planned work was evenly spread over 6 years as opposed to 5 years, an approximate $2M reduction to revenue requirement is expected. However, the 2024 completion date allows for a one year buffer to respond to new PCB discoveries in order to meet Environment Canada's deadline in 2025. Without a buffer, there is no time to address newly discovered issues that could place Hydro One in non-compliance with the PCB Regulation.[1]

[1] PCB Regulation SOR/2008-273

OEB INTERROGATORY #158

Reference:
F-01-03 p.10 and 12 Table 3

Interrogatory:
At the first reference above, it is stated that:

As part of the Transformer Oil Leak Reduction program, Hydro One plans to re-gasket 5 or 6 transformers per year, which is in line with the historical average.

At the second reference above, the proposed spending for 2020 in this category is $2.5 million, with spending varying in the 2015 to 2018 period from a low of $0.9 million in 2015 to a high of $4.1 million in 2017.

a) Please state what period the historical average represents.

b) Please explain the reasons for the variability of spending in this category in the 2015 to 2018 period.

Response:
a) 2014 to 2018 inclusive.

b) Spending varied during the 2015-2018 period because the cost of this work varies based on the type of and condition of the transformer being repaired. Spending in 2017 was higher than normal because of the costly corrective work for Bruce T25 (750MVA 500kV) unit which is the largest transformer in our fleet and contains 194,600 liters of oil. This resulted in higher cost to process its oil compared to an average power transformer.

OEB INTERROGATORY #159

Reference:

F-01-03 p.10 and 14-15 Table 3

Interrogatory:

At the first reference above, the Environmental Management OM&A category of "Environmental Compliance and Emergency Response Plan Updates" is discussed and it is stated that funding for Emergency Response Plans for the 2020 Test Year is in line with historical expenditures. With respect to Environmental Compliance, it is stated that:

The program was forecasted based on Ontario's Cap and Trade Regulations and was repealed on October 31, 2018. The regulations included detailed rules and obligations for businesses, such as Hydro One. In December 2018, the Ontario Government announced its new environment plan that is aimed at, among other things, addressing climate change by lowering greenhouse emissions. Details of the plan are not yet available. Furthermore, on October 23, 2018, the Government of Canada confirmed that Ontario would be covered by the federal Greenhouse Gas Pollution Pricing Act which imposes a price on greenhouse gas emissions in the province beginning in 2019.

At the above second reference above, spending for the 2020 Test Year is shown as $3.3 million, with spending in the 2015 to 2018 period ranging from $0.9 million to $1.8 million.

a) Please confirm that the significant increase in spending in this category in the 2020 Test Year arises from an increase in the Environmental Compliance component. If this is not the case, please explain the statement referenced above that funding for Emergency Response Plans for the 2020 Test Year is in line with historical expenditures.

b) Please state what component for the $3.3 million spending in this category is for Environmental Compliance and how Hydro One determined it was reasonable given the above reference to details of the Ontario Government's new environmental plan not being available when the forecast was being prepared.

Response:

a) Yes, spending in the 2020 Test year arises from an increase in the Environmental Compliance component.

b) The Environmental Compliance component accounts for $3 million of the total $3.3 million allocated as follows: Regulatory compliance effluent testing required by the Ministry of the Environment, Conservation and Parks ($0.6 million); Greenhouse gas emissions monitoring and reporting, including SF6 gas management and the associated quantification and verification for reporting and disclosure purposes ($0.5 million); and Cap and Trade compliance ($1.9 million).

   Since submitting this Application, the original forecast of legislative obligations related to Cap and Trade did not come into effect. Hydro One has allocated this funding to address a recently discovered issue affecting guyed towers. Guyed towers were found to have loose bolts and guy-wires below their design tension. This is a serious issue that can result in tower failure and/or conductor drop and is a significant safety and reliability risk. Hydro One will use this $1.9 million to torque bolts and tension guys on the affected structures.

OEB INTERROGATORY #160

Reference:

Exh F and EB-2017-0049 Decision and Order, Appendix 2

Interrogatory:

At the second reference above, the OEB directs Hydro One to do as follows:

Demonstrate, in future applications, that OM&A options are being explicitly considered in investment decisions to either replace or defer capital investments, as applicable.

a) Please discuss how Hydro One has reflected this direction in the application.

Response:

a) The proposed plan reflects the consideration of capital and OM&A options for all investments. Specifically, as part of the Investment Planning Process detailed in Exhibit B-1-1 TSP Section 2.1, Hydro One follows a detailed eight step investment process. During the "Needs Assessment" phase of the process, candidate investments are established for further consideration. Once an asset need is identified, specific OM&A activities are considered alongside capital investment options for all asset types (as described in Exhibit F, Tab 1, Schedule 3 "Sustaining OM&A") as potential solutions to address relevant risks, including asset condition deterioration and risk of failure or obsolescence.

   An example pertains to PCB mitigation of oil-filed equipment for both transformer and breaker investments, as described in Exhibit B-1-1 TSP Section 2.2. Hydro One balances key factors such as equipment condition, performance, and obsolescence in conjunction with meeting federal regulations requiring removal of PCB contaminated equipment by 2025. Where condition, performance and maintainability of the asset do not pose a material risk to the safe and reliable operation of the transmission network, Hydro One will include the solution of retro-filling that specific asset within the OM&A work program to ensure compliance and defer capital investment. In addition, as part of the continuous asset risk assessment ("ARA") process, transformers are evaluated on a repair vs. replace curve to establish a recommended replacement timeline in light of current and projected future OM&A expenditures balanced against asset condition and performance. This analysis feeds directly into the Investment Planning Process to establish recommended timelines for transformer replacements that are further assessed as candidate investments in the Investment Planning Process.

It is important to note that the Decision and Order in EB-2017-0049 was issued on March 7, 2019 and Hydro One submitted this application (EB-2019-0082) two weeks later on March 21, 2019. Hydro One has strived to be responsive to the OEB's directions, and believes its efforts in doing so, as well as the demonstrable strength of its evidence with respect to capital and OM&A trade-offs, were reasonable and appropriate, particularly in light of the above-noted timing constraints.

OEB INTERROGATORY #161

Reference:
Exh F and EB-2017-0049 Decision and Order, Appendix 2

Interrogatory:
At the second reference above, the OEB directs Hydro One to do as follows:

For any future Hydro One rebasing application, develop a consistent template for presenting compensation costs based on the direction provided by the OEB in prior proceedings.

a) Please discuss how Hydro One has reflected this direction in the application.

Response:
a) Following the filing of EB-2017-0049 (Distribution), Hydro One received the EB-2016-0160 (Transmission) decision whereby the OEB directed Hydro One to submit baseline compensation data for both the Transmission and Distribution businesses for the recently filed EB-2017-0049 filing.

In response, Hydro One filed a new compensation table in October 2017 (EB -2017-0049) Exhibit C1, Tab 4, Schedule 1 Attachment 6. This compensation table included total compensation for both the Distribution and Transmission businesses, expanded compensation elements, Year-end headcount, total headcount and FTEs. FTEs were used to generate the compensation dollars.

In order to show trends on the baseline compensation produced in Attachment 6, Hydro One has filed compensation data in this current application (Exhibit F, Tab 4, Schedule 1 Attachment 5) on the same basis.

The Decision and Order in EB-2017-0049 was issued on March 7, 2019 and Hydro One submitted this application (EB-2019-0082) two weeks later on March 21, 2019. Hydro One has taken all reasonable steps to be responsive to the OEB's directions, and believes its efforts in doing so were reasonable and appropriate, particularly in light of the above-noted timing constraints.

Witness: Sabrin Lila

OEB INTERROGATORY #162

Reference:
F-01-01 p.3

Interrogatory:
At the above reference, Hydro One states that:

Hydro One's 2019 OM&A expenses are expected to be $38 million or 9.6 percent lower than the 2018 plan funding envelope. This OM&A reduction will be achieved largely through sustained productivity gains, a one-time extension of Hydro One's planned asset maintenance cycles, and corporate cost reductions, which are described further within Section 6 of this Exhibit. Hydro One plans to increase its 2020 OM&A expenditures by 5 percent from 2019 levels while still remaining 4.7 percent below the 2018 plan funding envelope. The investment plan was designed to utilize the approved funding to improve reliability and maintain asset condition over the planning period. In this manner, the investment plan appropriately balances the need to minimize customer rate impacts with the requirements of the system for supporting the delivery of safe and reliable transmission service.

a) Please discuss whether or not Hydro One's ability to remain 4.7 percent below the 2018 plan funding envelope approved in the previous transmission application would reasonably raise concerns that it may be over-forecasting OM&A requirements in the current application.

b) Given that Hydro One's OM&A expenditures were running below the envelope approved in the previous application, please explain why it was considered necessary to undertake the above referenced one-time extension of planned asset maintenance cycles, along with the other cost containment measures also described.

Response:
a) In 2018, actual OM&A was $24.9 million or 6.3% above the funding envelope approved in the previous transmission application for 2018. In the current application, the funding envelope for 2020 Test Year is 4.7% lower than the 2018 approved amount. This demonstrates that Hydro One is asking for a lower OM&A funding

envelope, contrary to the statement made that Hydro One is over-forecasting OM&A requirements in the current application.

Comparison of historical performance relative to prior approvals must include consideration of the contributing factors to the variances. The largest cost drivers (Sustainment, Operations), which have enabled the safe and reliable operation of the transmission system historically, are consistent within or below historic levels and reflect a level of expenditure which will ensure the continued safe and reliable operation of the transmission system in the future.

b) Per Table 1 of Exhibit F-01-01, Hydro One's originally forecasted 2018 OM&A expenditures were $5.1 million above the approved funding envelope. As part of the blue page update, the actual OM&A variance was updated to $24.9M above 2018 approved funding envelope. Hydro One implemented the noted measures to manage the transmission business within the approved revenue requirement envelope for 2019. The approved revenue requirement for 2019 was derived using a one year inflationary adjustment mechanism relative to 2018 approved revenue requirement.

OEB INTERROGATORY #163

Reference:
Exh F and EB-2016-0160 Decision and Order Revised: November 1, 2017, p.62-63

Interrogatory:
At the second reference above, the OEB expressed its concern about Hydro One's historic pattern of OM&A under-expenditure since 2012 and provided the following direction:

In future applications, the OEB directs Hydro One to provide a high level description of the main contributors to any material variance between approved and actual total OM&A expenditures in previous applications and the impact of those variances on its longer-term ability to operate and maintain its assets. This information would enable the OEB to determine if there are fundamental issues affecting Hydro One's ability to complete the planned work program and the potential impact of these issues on future proposed work programs.

a) Please discuss how Hydro One has complied with this direction in the current application.

Response:
a) Please refer to Exhibit F, Tab 1, Schedule 1 for a discussion of actual OM&A vs plan.

OEB INTERROGATORY #164

Reference:
F-01-05 p.3

Interrogatory:
At the above reference, Hydro One states, in providing variance explanations for Operations OM&A, that:

The 2020 test year proposed spending represents an increase of $2.8 million relative to the 2019 bridge year forecast expenditures. The increase is necessary to reinstate the Operations Support work programs that were part of the unsustainable reductions in in 2018 and 2019 as noted below. Even with this increase, the 2020 proposed level still remains below the previous Board-approved amounts.

a) Please explain why Hydro One considered it necessary to make an unsustainable reduction in Operations Support work programs in 2019 to align with the OM&A envelope in the inflation application. Please discuss this in the context of the statement that the 2020 proposed level still remains below the previous Board-approved amounts.

Response:
a) Please refer to interrogatory response I-01-OEB-186.

For 2020, Operations Support's OM&A spending increases from 2019 but remains below its 2018 OEB-approved amounts. Relative to 2018, Operations Support's OM&A costs in 2020 have decreased as a result of finding efficiencies and savings.

OEB INTERROGATORY #165

Reference:

F-02-04 p.11

Interrogatory:

At the above reference, Hydro One discusses anticipated reductions in its IT Management and Project Control OM&A Allocated to Transmission and states as follows when explaining the significant reductions in these costs anticipated for 2019 and 2020:

Historical actuals for IT Management & Project Control are trending down. The proposed IT Management & Project Control OM&A expenditure for the 2020 Test year is 22.1%, 41.2% and 4.8% lower than the 2018 forecast expenditure, 2018 Plan and 2019 Forecast amounts respectively. Hydro One attributes this decreasing trend to an updated actuarial pension valuation, which reduced operating expenses across the company, lower headcount and increased labour recovery related to IT capital projects portfolio expenses.

a) Please clarify whether or not the reference to lower headcount relates to general reductions, or reductions specific to the IT area.

b) Please explain why there was increased labour recovery related to IT capital projects portfolio expenses.

Response:

a) Reductions referenced in the excerpt above were specific to the IT area.

b) Beginning in 2018, IT aligned its resources within the capital work program to enable more accurate labour recoveries.

OEB INTERROGATORY #166

Reference:
F-02-04 p.14

Interrogatory:
At the above reference, Hydro One explains changes in the ratio of IT spend as a percentage of operating expense and states that "2017, 2018, 2019 and 2020 figures reflect lower costs of power related to Fair Hydro Plan."

a) Please state why Hydro One cited this specific factor in explaining these changes.

Response:
a) As detailed in Exhibit F, Tab 2, Schedule 4 Page 13, "Operating Expenses" includes OM&A, cost of power, and depreciation.

Witness: Lincoln Frost-Hunt

OEB INTERROGATORY #167

Reference:

F-03-01 p.5

Interrogatory:

At the above reference, it is stated that:

Inergi's services are also measured through client satisfaction surveys conducted by Inergi of Hydro One's relevant business managers and internal users. Inergi must address dissatisfaction revealed by the surveys. Together, Hydro One and Inergi are to identify opportunities and strategies for responding to any issues the surveys reveal. The most recent surveys showed scores of 3.32 out of 5 for Base Services and 3.96 out of 5 for Project Services and service desk support.

a) Please comment on the above scores, in particular the 3.32 out of 5 for Base Services and whether these scores reveal any issues with the services provided by Inergi to Hydro One. If the scores reveal any issues, please explain what they are and what is being done about them. If they don't, please explain why not.

Response:

a) With respect to Base Services, Hydro One is working with Inergi to implement continuous improvement initiatives such as automation and process improvements, plus increased visibility to Capgemini global best practices to improve future client satisfaction survey results.

   Hydro One was satisfied with the delivery of Project Services.

OEB INTERROGATORY #168

Reference:
F-04-01 p.2

Interrogatory:
At the above reference, it is stated that:

Having clear and visible values helps Hydro One in its decision-making processes. For example, the value of "Win as One" fosters a shared understanding within the company that a successful decision is one that leads to an outcome that considers the needs of Hydro One, its customer, its employees, and its shareholders.

a) Please explain how Hydro One determines whether or not a decision is successful.

b) Please state how Hydro One would balance the needs of Hydro One, its customers, its employees, and its shareholders in making a determination that a decision is successful.

Response:
a) Decision success is subjective. Making or justifying a decision by only considering a single value, rather than several, could mean that not all potential options have been considered.

   Decisions made that have considered several values allow for a balanced perspective where multiple viewpoints have been explored, and a more thorough decision has been made. This more robust decision making process leads to better decisions, regardless of if they are ultimately judged as successful.

b) Hydro One, by nature of its business structure, considers the needs of employees, customers and shareholders when making decisions. The appropriate balance is reached on a case by case basis.

OEB INTERROGATORY #169

Reference:
F-04-01 p.2

Interrogatory:
At the above reference, it is stated that:

Values help communicate to key stakeholders, such as shareholders and customers, the identity of the company and what it is about. Having a clearly articulated and specific set of core values provides a competitive advantage to Hydro One and assists it in working with these and other stakeholders.

a) Please state what is meant by the competitive advantage that Hydro One has as a result of its core values.

b) Please provide some examples of how this has worked to benefit Hydro One.

Response:
a) Having a set of clearly articulated core values, and supporting behaviours, is a competitive advantage to Hydro One, because it enables the company to describe the culture that it is striving to create. This is an advantage when recruiting and retaining talent, as alignment between personal and company values is increasingly important when choosing an employer. The advantage is in helping both company and employee identify ‘good’ fit versus ‘bad’ fit based on how personal and company values align. This removes some risk in the recruiting process, and can provide a tool to evaluate the ongoing retention of employees. Employees with strong alignment between personal and company values tend to more satisfied and engaged in their work, which can translate into better customer service and quality work products that benefit all shareholders.

b) The benefit of clearly articulated core values, and supporting behaviours, is that potential recruits and existing employees who see strong alignment between their personal and company values tend to see greater job satisfaction, organizational commitment, motivation, feeling of personal success, and greater concern for customers and stakeholders than those who do not.

The current VP, Transmission & Stations and Interim Chief Operating Officer (COO) are prime examples of this. The Interim COO started over 30 years ago as a Regional Maintainer, Electrical. The VP, Transmission & Stations, started 17 years ago as a New Graduate. Values are a powerful concept to help individuals in career decisions and retention.

Anecdotally, external applications frequently comment on Hydro One's core values and how they find these aligned with their personal values as a reason for showing interest in Hydro One. Employee alignment with company values can lead to greater job satisfaction and motivation which, for employees dealing with customers, translates into a high level of customer service and satisfaction.

OEB INTERROGATORY #170

Reference:
F-04-01 p.12

Interrogatory:
At the above reference, it is stated that:

To further improve resource planning, in 2019, Hydro One launched the Operational Workforce Planning initiative to ensure it has the right workforce to support the business strategy and current and future work program requirements. The purpose of the program is to enhance short and long-term headcount management efforts and to provide insights on current and future talent requirements.

a) Please discuss how and why Hydro One decided to launch this initiative and to what extent it was developed within Hydro One as compared to being an approach already in use in other organizations which was adapted to Hydro One.

b) Please state whether any significant cost savings are expected to arise from this initiative and if so what they are and when they are expected, including the impact on FTEs in 2019 and going forward.

Response:
a) Hydro One launched the Workforce Planning initiative in order to continue enhancing our headcount management efforts. The process is designed to 1) align the workforce requirements to business strategy, 2) improve our knowledge of the talent requirements over time, and, 3) continuously improve our management of operating expenses by strategically resourcing the workforce. The Workforce Planning framework was created in-house based on external best practices, tailored to fit the unique nature of our business.

b) The primary focus of the Workforce Planning initiative is to anticipate future workforce needs to enhance our ability to develop the appropriate talent pipeline (either internal or external) and continuously improve our planning and budgeting process. This process is expected to improve our forecasting. However, given this is our first cycle, it is too soon to anticipate any specific savings.

Witness: Sabrin Lila

OEB INTERROGATORY #171

Reference:
F-01-01 p.3 Table 1, F-04-01 p.13 Table 2,F-01-02-01 p.5

Interrogatory:
At the first reference above, Hydro One's Total Transmission OM&A expenses are shown as decreasing from $385.0 million in 2017 to $375.8 million in the 2020 Test Year, which represents a decrease of over 2%

At the second reference above, Hydro One's Grand Total FTEs are shown as increasing in the same period from 8,146 to 9,146, an increase of over 12%.

At the third noted reference Appendix 2-L "Recoverable OM&A Cost Per Customer and per FTE." is shown.

a) Please update Appendix 2-L to reflect both 2017 and 2018 OEB-approved FTEs. If these numbers are not available, please provide an estimate.

b) In general, OEB staff notes that OM&A is decreasing, while the number of FTEs is increasing. Please confirm and explain the following movements in OM&A and FTEs in the table below:

	2019 forecast over 2018 actual	2020 forecast over 2019 forecast		2020 forecast over 2018 actual	2020 forecast over 2018 OEB approved
OM&A	-14.9%	5.4%		-10.3%	-4.7%
FTEs	9.3%	-0.8%		8.5%	n/a

Response:
a) The OEB process approves Hydro One's overall spending envelope and therefore not the specific labour mix and FTEs.

b) Confirmed, the OM&A calculation analysis is correct. Exhibit F, Tab 1, Schedule 1, and associated sections within outline spending trends and variances at a summary level, however if detailed explanations are required, please refer to:

Sustainment: Exhibit F, Tab 1, Schedule 3
Development: Exhibit F, Tab 1, Schedule 4
Operations: Exhibit F, Tab 1, Schedule 5
Customer Care and Corporate Affairs: Exhibit F, Tab 1, Schedule 6
Common Corporate Costs and Other OM&A: Exhibit F, Tab 2, Schedule 1

An explanation of the FTE increase is provided in F-04-01 page 13 – 15 and further explained Exhibit I, Tab 01, Schedule OEB-196.

While analyzing FTE changes to OM&A trends is a reasonable comparison, it does not tell the full picture as the full work program is not considered when only focusing on OM&A.

OEB INTERROGATORY #172

Reference:
F-04-01 p.13 Table 2
EB-2017-0049 C1-02-01 p.9 Table 1

Interrogatory:
At the first reference above, Hydro One's Full Time Equivalents (FTE), 2017 to 2022 are shown as increasing from 8,146 to 9,146, an increase of over 12%. At the second reference above it is stated that "Table 1 illustrates the forecast FTEs for 2017 to 2022. Total Regular FTEs and total Networks FTEs in 2022 are expected to be 2.0% and 1.3% lower respectively than in 2017." FTE numbers decrease from 8,581 in 2017 to 8,467 in 2022.

a) Please reconcile the FTE numbers in these two tables and explain the shift to a 12% increase in the transmission application from a 2% decrease in the distribution application.

Response:
a) Different business plans underpin rate filings EB-2017-0049 and EB -2019-0082. The 2017-2022 Business Plan was the basis for EB-2017-0049 (and in update Exhibit Q, the 2018-23 Business Plan was used). In the current application, Business Plan 2019-2024 is the basis of the evidence.

It should be clarified that while this question refers to a 12% increase in FTEs over the period 2017 to 2022, the table below shows that Transmission related FTEs increase 7% over the same period.

Transmission FTE		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Regular	MCP	308	290	307	334	345	336
	Society	627	607	699	755	778	754
	PWU	1,645	1,602	1,658	1,827	1,900	1,862
Total		**2,580**	**2,499**	**2,664**	**2,916**	**3,023**	**2,952**
Non Regular		**1,724**	**1,748**	**1,811**	**1,775**	**1,715**	**1,661**
Total Transmission FTE		**4,304**	**4,247**	**4,475**	**4,691**	**4,738**	**4,613**

Witness: Sabrin Lila

OEB INTERROGATORY #173

Reference:
F-04-01 p.37 Table 8

Interrogatory:
Table 8 provides "Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median." This table shows that while Hydro One improved in the 2008 to 2017 period by 5%, it worsened by 2% in the more recent 2013 to 2017 period.

a) Please discuss the reasons for the deterioration in the 2013 to 2017 period.

Response:
a) During the 2013 to 2017 period, overall Hydro One moved from a weighted average multiple of Market of 1.10 to 1.12. The findings for the Hydro One Groups, that make up the overall figures did not all move identically. Specifically:

- Non-Represented – remained within 1% of its stated target of Market P50 moving from 0.99 in 2013 to 1.01 in 2017
- Trades & Technical – remained flat at a multiple of 1.12 of Market P50
- Energy Professionals – 2017 multiple of Market P50 was 1.12, up from 1.09 in 2013

Each Benchmark Study is predominantly a point in time comparison of Hydro One's total compensation to the Market. The Study findings, in this case the multiple of Market P50, is a function of both Hydro One's compensation practices and the "Market's" compensation practices. The tables below, list some of the factors that have impacted the Study outcomes.

Table 1

Market Factors - Impacting Study Findings
• Organizations agreeing to participate in the study – combination of peer group definition and success in soliciting participation • Current total compensation programs at the participating organizations – mix and relative magnitude • Changes in compensation programs since the prior study – cost containment efforts, cost sharing, plan enrichment, outsourcing, insourcing, etc. • Negotiated results of collective bargaining • Benchmark jobs matched by the participants

Table 2

Hydro One Factors - Impacting Study Findings
• Current total rewards programs • Introduction of new compensation arrangements designed to increase productivity and/or reduce employer costs going forward – lump sums, share grants, cost sharing • Benchmark jobs included in the study • Use of alternative staffing models (hiring hall, casual employment, outsourcing, insourcing, etc.) • Negotiated results of collective bargaining

All of these factors were "in play" and impacted the results of the 2013 and 2017 marketplace. It is challenging to identify the specific factors contributing to relatively small changes in the multiple of Market P50 for the near target Non-Represented Group and the flat multiple for the Trade & Technical Group.

OEB INTERROGATORY #174

Reference:

F-03-01 p.2

Interrogatory:

At the above reference, it is stated that: "Hydro One relies on two main outsourcing arrangements in the operation of its businesses, one with Inergi LP ("Inergi") and another with Brookfield Asset Management."

a) Please state the percentage of Hydro One's total outsourcing dollars spent that are encompassed by these two agreements.

b) Please show the impact of the total outsourcing dollars on the 2020 test year revenue requirement, including the impacts on both 2020 OM&A and 2020 capital.

Response:

a) These 2 contracts represent 100% of outsourcing dollars spent.

b) The impact of the total outsourcing dollars on the 2020 test year revenue requirement is forecasted at $56.1 million.

The impact on 2020 OM&A is forecasted at $53.6 million.

The impact on 2020 capital is forecasted at $2.5 million.

OEB INTERROGATORY #175

Reference:
F-03-01 p.3-4

Interrogatory:
At the above reference, it is stated that the Inergi Agreement provides for optional benchmarking reviews of fees by an independent third party, but that to date Hydro One has not exercised its option to benchmark. This decision is stated as being largely attributable to the integration of the customer service operations and the re-negotiation of information technology and supply chain SOWs (Statement of Work) which financially make up the majority of the contract at approximately 88%.

a) Please explain why Hydro One did not have the fees benchmarked before undertaking the above two referenced steps.

Response:
a) Hydro One has not exercised its right to benchmark as the customer services Statement of Work (SOW) was near term and was insourced and the 2 SOWs for information technology and Supply Chain were renegotiated. We have recognized savings of approximately 11% in 2020 as a result of the renegotiations.

OEB INTERROGATORY #176

Reference:
F-03-01 p.4-5

Interrogatory:
At the above reference, Table 1 provides Inergi's 2018 performance. It is stated that service quality is measured using defined service levels or Performance Indicators (PIs) and client satisfaction surveys and that the PIs are adjusted upwards annually, where applicable to drive continuous improvement.

a) Please describe the process by which the PIs are adjusted annually and how it is determined whether or not such adjustments are applicable.

b) Please discuss why Inergi only met 82% of its performance targets in 2018 and whether or not Hydro One viewed this as an acceptable level of performance. If Hydro One considered this an acceptable performance level, please explain why. If not, please describe any actions that will be taken in response to it.

Response:
a) Adjustments to Performance Indicators (PIs) are calculated based on previous years' PI results as per the Inergi Agreement with the exception of PIs already at the highest possible service level which remain unchanged.

b) Overall PI Performance was 93% and in Payroll Services, Inergi met 82% of its PIs. Opportunities to improve Payroll Services PIs around timeliness and overall satisfaction of responses to requests were identified. Inergi has implemented the following remediation actions:
   i. Frequent monitoring of the logging tool and prioritization of work;
   ii. Additional training in customer service;
   iii. Availability of trained backup resources.

OEB INTERROGATORY #177

Reference:
F-03-01 p.8

Interrogatory:
At the above reference, it is stated with respect to the BGIS contract fees that:

BGIS receives annual management and administrative fees which include overhead and profit. This fee is adjusted annually for inflation in accordance with the consumer price index and as necessary in the event of material changes in the scope of the work. Built into the fee structure are incentives for BGIS to achieve cost savings….

Hydro One may request third party benchmarking after three years and every two years thereafter, with a "benchmark fee adjustment", if the aggregate fees are above five percent of the target results….

The BGIS Agreement provides for Critical Service Levels ("CSL"), Key Performance Indicator ("KPI") measures and critical deliverables. BGIS's services are measured and reviewed regularly (monthly, quarterly and annually) to validate achievement of KPIs.

The CSLs and KPIs are based on the nature of the services provided by BGIS and set forth both expected and minimally accepted service levels. If BGIS fails to meet specific criteria, there are adverse financial consequences for BGIS.

a) Please describe how incentives for BGIS to achieve cost savings are built into the fee structure. Please discuss what the adverse financial consequences for BGIS would be if BGIS fails to meet the specific criteria.

b) Please state whether or not Hydro One has requested third party benchmarking to date with respect to this contract and whether or not it has any plans to do so in the future. Please also explain why or why not this is the case.

Response:
a) The contract contains several cost saving incentives built into the fee structures. BGIS is required to provide an Annual OM&A Budget and shall use reasonable

efforts to manage assigned contracts to reduce pass –through expenses. The overall Management Fee contains a discretionary portion and an 'at risk' portion which is tied directly to the Critical Service Levels (CLS) structure. BGIS is required to provide Hydro One a credit based upon a contractually agreed to formula if a specific criteria is not met. The contract also allows for savings made in Reimbursable Charges to be shared equally by Hydro One and BGIS.

For Capital Projects, there is a requirement for BGIS to generate savings across all projects taken as a whole.

b) A third party benchmarking exercise has not been conducted to date. Currently we are in year five of the ten year agreement and our intention is to perform a benchmarking study in the near future.

OEB INTERROGATORY #178

Reference:

F-04-01-01

EB-2017-0049 Management and Non-Represented Role Benchmarking and 2018 Compensation Structure Recommendations, C1-02-01-01, C1-02-01-02

Interrogatory:

The first reference above is a compensation study prepared by Willis Towers Watson for the current application.

The second reference lists three compensation studies prepared by either Willis Towers Watson or Towers Watson for Hydro One's recent distribution rates application.

a) Please state how the study in the current application relates to the three studies filed in the previous application.

b) Please provide a table summarizing and comparing the key recommendations of the current study with those in the previous studies. Please include an explanation for any changes between the recommendations in the current study and those in the previous application, particularly with respect to recommended levels of compensation.

c) Please describe how Hydro One's consideration of the above referenced studies impacted the requested 2020 test year revenue requirement, including the impacts on both 2020 OM&A and 2020 capital.

Response:

a) All four studies provide a market competitive assessment of Hydro One's Management remuneration arrangements. Each study assesses different subsets of Hydro One's management employee group, and different components of Hydro One's remuneration programs relative to market. The table below provides a summary of each study as it relates to the area of focus, and management employees included in the analysis. This year's study is most similar in scope to (2) EB-2017-0049 Management and Non-Represented Role Benchmarking and 2018 Compensation Structure Recommendations Filed: 2018-04-20.

Study Reference	Competitive Assessment Area of Focus	Employee Groups Assessed	
		Executives	Management Employees
Exh F-4-1 Attachment 1	Compensation structure (1)	✓	✓
EB-2017-0049	Compensation structure (1)	✓	✓
Exh C1-2-1 Attachment 1	Total rewards (2)	✓	
Exh C1-2-1 Attachment 2	Total rewards (2)		✓

1. Compensation structure is defined as salary midpoint + target short-term incentives + expected value of long-term incentives
2. Total rewards is defined as salary + target short-term incentives + expected value of long-term incentives + pension & benefits

b) The table below summarizes the key recommendations of the current and previous compensation studies conducted by Willis Towers Watson.

Study Reference	Recommendation Focus	Willis Towers Watson (WTW) recommendations
Exh F-4-1 Attachment 1	Salary Increase Budgets	WTW recommended a 2019 salary increase budget of 2.5%. No adjustments to the salary structure were recommended
EB-2017-0049	Salary Structure	WTW recommended modest salary structure adjustments to align closer to the market 50th percentile
EB-2017-0049	Long-term Incentives	WTW recommended increasing participation levels of Hydro One's long-term incentive program at the Director level, along with adjustments to the mix of incentive vehicles, to better align with typical market practice of similar organizations
Exh C1-2-1 Attachment 1	Executive Compensation Peer Groups	WTW recommended selection criteria to establish a broader secondary executive compensation peer group, and an annual review process, to ensure continued appropriateness of the underlying peer groups
Exh C1-2-1 Attachment 1	Transition / implementation	WTW recommended a transitional approach in managing executive compensation relative to market, i.e. current executive roles may not immediately need to be aligned with the market 50th percentile ,and can be transitioned over time
Exh C1-2-1 Attachment 2	Pre- IPO Considerations	WTW recommended Hydro One consider transition planning timeline as it relates to salary structure development and administrative guidelines, incentive

		programs (both executive and non-executive), salary budget increases and implementation guidelines, which better reflect the new ownership structure
Summary: In each instance, WTW's recommendations included in the four studies reflected Hydro One's current and future desired state. As Hydro One's compensation programs evolved, recommendations were made to also support an evolving compensation program in terms of both design and administration, and align with its peer group as a publicly-traded company to establish good corporate governance. The approach to recommendations associated with levels of compensation were consistently provided to ensure Hydro One remained competitively positioned to market in order to attract and retain talent, while ensuring appropriate cost-control measures were considered.		

c) Management regularly benchmarks compensation with its consultant Willis Towers Watson. These studies are used to inform compensation decisions that may impact in year compensation. For example, Willis Towers Watson's recommendation for merit was 2.5% for management, whereas this Application assumes a 2% escalation, and therefore has no impact on the revenue requirement. Other recommendations may have an on-going impact, which are reflected in the labour burdens for each rate application.

OEB INTERROGATORY #179

Reference:
F-06-01-02

Interrogatory:
OEB Staff seeks additional information in order to better understand the growth in capital cost resulting from the forecasted capital additions during the term of the Custom IR plan.

a) Please provide the depreciation expenses associated with the gross plant additions that Hydro One proposes to make in each year of the Custom IR term (e.g., depreciation expense for each of the 2020, 2021, and 2022 plant additions) by completing the table below.

		Depreciation Expenses from Gross Capital Additions		
Year Addition Placed Into Service		**2020**	**2021**	**2022**
	2020			
	2021			
	2022			

b) Please confirm that Hydro One has not requested accelerated depreciation of these assets, and that, for regulatory rate-making purposes, the half-year rule would apply to these plant additions for the year in which they are placed in service.

Response:
a) Please see the table below for depreciation expenses associated with the gross plant additions for the years 2020-2022.

		Depreciation Expenses from Gross Capital Additions		
Year Addition Placed Into Service		**2020**	**2021**	**2022**
	2020	12.9	25.3	24.7
	2021	-	16.9	33.4
	2022	-	-	14.4

**figures in millions*

b) Hydro One confirms that it is not requesting accelerated depreciation on its capital asset additions for accounting purposes (depreciation expense in the revenue requirement), and that the half-year rule would apply to these plant additions.

For information regarding the impact of tax related legislation changes regarding accelerated depreciation, please refer to Exhibit I, Tab 01, Schedule OEB-208.

OEB INTERROGATORY #180

Reference:
A-03-01 p.25 , F-02-02 p.4

Interrogatory:
At the first reference above, the following is stated:

The changes in the Hydro One Transmission portion of CCF&S costs are largely due to the same factors noted above for changes in total CCF&S costs. The allocation of cost to transmission in the 2020 test year is lower than 2015 actuals despite inflationary pressures. This is the result of Hydro One's application of 'transformation costs' to pre-IPO levels, Bill 2 legislation and corporate cost reductions previously described in Exhibit F, Tab 2, Schedule 1, page 1. Table 3, below, shows the detailed breakdown between labour, non-labour and where appropriate, other costs included in the CCF&S costs for the Bridge and Test period.

At the second reference above, the following is stated:

In developing its Investment Plan, Hydro One utilized the Ontario Consumer Price Index ("CPI") for its assumptions about inflation. A CPI of 2% was assumed over the planning period…

OEB staff notes that Hydro One refers to inflationary pressures when explaining variances in certain OM&A costs.

OEB staff further notes that the inflation rate calculated by the OEB for rate changes effective in 2019 is 1.5%.[1]

a) Has Hydro One used a 2% inflation rate to budget OM&A expenses for the 2020 test year? If yes, please explain including why Hydro One didn't used the OEB inflation rate referenced above. If no, please explain what inflation rate Hydro One has used and why.

1 2019 EDR Webpage November 23, 2018 Reference – "…the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2019, to be 1.5%..."

Response:

a) Hydro One did not use 2% inflation rate to budget OM&A expenses for the 2020 test year. Hydro One used a 2% Ontario Consumer Price Index ("CPI") for assumptions about inflation for work program costs, which informed the base for relative year over year change for bottom up investment programs, based on changes to volumes, work practices and productivity.

OEB INTERROGATORY #181

Reference:
A-03-01 p.40

Interrogatory:
At the reference above, the following is stated:

A summary of forecast OM&A expenses for the 2020 test year is provided in Exhibit F, Tab 1, Schedule 1. These amounts have been reduced by the OM&A productivity savings outlined in Table 2 of this Exhibit. As shown in Table 9, 2020 OM&A expenses are expected to be $18.5 million lower (4.7%) than the 2018 OEB-approved (plan) funding envelope and are $34 million lower than what they would be if 2018 OEB-approved funding levels were increased at a 2% rate of inflation in 2019 and 2020

a) Please provide a revised calculation of 2020 OM&A expenses if the OEB inflation rate of 1.5% is used in place of the 2% inflation rate assumed by Hydro One.

Response:
a) 2020 OM&A expenses are expected to be $18.5 million lower (4.7%) than the 2018 OEB-approved (plan) funding envelope and are $30 million lower than what they would be if 2018 OEB-approved funding levels were increased at a 1.5% rate of inflation in 2019 and 2020[1].

[1] 2018 OEB-approved OM&A inflated by 1.5% would have resulted in OM&A of $400.2 million in 2019 and $406.2 million in 2020

OEB INTERROGATORY #182

Reference:

A-03-01 p.40

Interrogatory:

At the reference above, the following is stated:

These reductions were achieved primarily through a reduction in vacancies and by limiting consulting and contract engagements to critical functions, which also assist in strengthening and building internal capabilities.

a) Please provide the impact of these actions on FTEs and compensation (both capital and OM&A) in 2020 as well as the impact on the 2020 revenue requirement.

Response:

a) The impact of these actions in 2020 is a reduction of 34 FTEs across the corporate groups which translates to $7.2 million in Tx Capital and $7.2 million in Tx OM&A related to labour costs. When combined with consulting and contract reductions the total impact is $9.7 million in Tx OM&A and $13.5 million in Tx Capital, or an overall impact of $11.1 million in 2020 Revenue Requirement as outlined in Exhibit I, Schedule 1, Tab 1, Schedule OEB-185.

Witness: Joel Jodoin

OEB INTERROGATORY #183

Reference:

A-03-01 p.3 and 40

Interrogatory:

At the first reference above, the following is stated:

Hydro One expects safety and reliability performance to be maintained over the TSP planning period at the proposed funding levels.

At the second reference above, the following is stated:

Hydro One's plan will address critical safety and environmental risks in its system. It will improve reliability performance by 13% to return to the top quartile performance that Hydro One's transmission customers are expecting.

a) Please reconcile the two statements above with respect to the stated intention to maintain reliability in the first and to increase it by 13% in the second.

b) Please provide more detail as to why a top quartile reliability performance is needed, versus the status quo second quartile reliability performance.

c) Please discuss the basis for Hydro One's view that its customers are expecting it to return to top quartile performance

d) Please quantify the impact on the 2020 revenue requirement, including the impacts on both OM&A and capital, if Hydro One was to remain at its present level of reliability performance.

Response:

a) In the context of a 9.6% reduction of OM&A in 2019 relative to 2018 approved levels and a 4.7% reduction of proposed OM&A in 2020 relative to 2018 approved levels, Hydro One does not expect reliability performance to be impacted detrimentally, resulting in the use of the phrase "maintain". Through an integrated investment plan, which includes system renewal and performance enhancement investments to address outlier delivery points, reliability performance improvements are forecast.

b) As part of the Customer Engagement undertaken in 2017 in support of this application, and detailed in Exhibit B, Tab 1, Schedule 1, Section 1.3, Customer, when presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in the 2017 to 2018 proceeding (Scenario C), which was presented as a plan that would reduce reliability risk and improve long-term reliability performance. 2018 was a challenging year from a reliability perspective; Hydro One believes providing service consistent with and better than historic levels is reflective of the feedback received from customers.

c) See b) above.

d) The feedback from the customer engagement survey, including an expression that reliability, outage restoration, and power quality are priorities and an indication that reliability improvements are a preference through the clustering around Scenario C with a moderate rate increase. Hydro One has not developed a “maintain” reliability scenario, and so is unable to provide a revenue requirement impact associated with such a scenario.

OEB INTERROGATORY #184

Reference:
A-03-01 p.40

Interrogatory:
At the reference above, the following is stated:

2019 OM&A expenditures are lower than the proposed test year OM&A as a result of the need to align to the funding envelope afforded in Hydro One's 2019 transmission revenue cap adjustment application (EB-2018-0130). This maintenance reduction has included reductions in activities including a one year extension of planned maintenance and asset condition assessments and represents a managed increase in asset risk that may manifest in terms of increased corrective/demand failures and/or reduced asset useful life but can be contained with a one year reduction in work and will be managed and mitigated in future years.

a) Please provide further explanation as to why the 2019 maintenance reduction, including a one year extension of planned maintenance and asset condition assessments, represented a managed increase in asset risk.

b) Please provide further explanation as to why Hydro One is of the view that this reduction may manifest in terms of increased corrective/demand failures and/or reduced asset useful life.

c) Please quantify and explain the impact of the 2019 extension of planned maintenance and asset condition assessments on both the 2019 and 2020 revenue requirements, including the impacts on both OM&A and capital.

d) Please provide further explanation as to why the 2019 extension of planned maintenance and asset condition assessments could not be repeated in 2020.

e) Please provide the impact on the 2020 revenue requirement, including the impacts on both OM&A and capital. If the 2019 extension of planned maintenance and asset condition assessments was repeated in 2020.

Response:

a) The 2019 maintenance reduction represents a managed increase in asset risk due to the following reasons:
   - As described in Exhibit F-01-01 page 4, "the 2019 bridge year forecast for Sustainment OM&A is lower than historical levels partially as a result of a one-time extension of Hydro One's planned asset maintenance cycles."
   - As described in Exhibit F-01-03 page 4, the maintenance reduction is made on work programs that posed the lowest risk to safety, system reliability and customer expectations. This includes fewer planned demand and corrective expenditures, extension of the PCB testing and retrofill program, deferral of overhead transmission line preventive maintenance and deferral of vegetation management on select 115kV circuits. High risk work programs are planned for execution in 2019.
   - Reduction in inspection and preventive maintenance typically wouldn't result in immediate asset failures. However continued funding at 2019 level will result in increased system risk, over the long term.

b) An extension of planned maintenance and asset condition assessments reduces Hydro One's ability to identify and address defects and deteriorating conditions earlier, which may result in a risk of increased outages caused by component failures that might have been identified during these activities.

c) As noted in Exhibit F, Tab 1, Schedule 1, page 4, the impact of the extension of sustainment maintenance cycles resulted in a one year reduction of $28.8 million relative to the 2018 Actuals. As noted in Exhibit A, Tab 3, Schedule 1, Hydro One applied for a one-year mechanistic adjustment to Hydro One's 2019 revenue requirement (EB-2018-0130); as a result, a notional $28.8M reduction to revenue requirement was incurred, which is offset by other components of the revenue requirement. The 2020 sustainment OM&A proposal continues to be $15.2 million below the 2018 Actuals, resulting in a notional revenue requirement decrease of $15.2 million, which is also offset by other components of the revenue requirement.

d) The extension of planned maintenance and asset condition assessments beyond one year is not prudent and cannot be repeated indefinitely. Excluding this work from 2020 would exclude funding for this work over the entire test period of 2020-2022. It would in essence take a one-year cut to preventive maintenance and condition assessments which represent a managed risk and extend it over a four year period. This would lead to an unmanaged risk. Hydro One had to make certain reductions and deferrals to its maintenance programs in 2019 in order to manage its OM&A spending within approved levels. Through a revised preventative maintenance cycle analysis, Hydro One temporarily reduced the transformers, circuit breakers, and switches maintenance programs in 2019. This one-time maintenance reduction represented a managed increase in asset risk, which is not sustainable through to 2022, as constant deferrals and reduced maintenance cycles ultimately give rise to increased equipment failures and pose unacceptable safety and reliability risks which will adversely affect Hydro One's customers and system reliability.

e) If sustainment maintenance were held at 2019 levels for 2020, revenue requirement would be reduced by $13.6 million. Hydro One notes that its 2020 proposed OM&A spending its 5% less than its 2018-Approved OM&A and that its 2020 Sustaining OM&A is in fact lower than the prior five year average spending (2015-2019). As noted in Exhibit F, Tab 1, Schedule 3, at pages 4 to 5, continued funding at the 2019 level, or a reduction below the 2020 forecast amount, will pose unreasonable safety and reliability risks, which will adversely affect Hydro One's ability to meet its customer needs and priorities.

OEB INTERROGATORY #185

Reference:
A-03-01, F-01-01

Interrogatory:
At the references above, Hydro One's derivation of its 2020 level of requested OM&A is discussed.

a) Please provide a summary table quantifying the impacts on the 2020 revenue requirement, including the impacts on both OM&A and capital, due to Hydro One's efforts, as noted in the references above, in the areas listed below:
   i. The management of maintenance cycles
   ii. The company-wide exercise undertaken by Hydro One to review and reduce corporate common costs as primarily achieved by:
      1. The reduction in vacancies
      2. The limiting of consulting and contract engagements to critical functions
   iii. Sustained productivity gains
   iv. The renegotiation of the Inergi outsourcing agreement

Response:
a) The impact to 2020 Revenue Requirement reductions are quantified below:

<table>
<tr><th></th><th>OM&A</th><th>Capital</th><th>2020 Revenue Requirement Impact</th></tr>
<tr><td>Management of Maintenance Cycles*</td><td>($15.2M)</td><td>-</td><td>($15.2M)</td></tr>
<tr><td>The reduction in vacancies</td><td>($7.2M)</td><td>($7.2M)</td><td rowspan="2">($11.1M)</td></tr>
<tr><td>Limiting of consulting and contract engagements</td><td>($2.5M)</td><td>($6.2M)</td></tr>
<tr><td>Sustained Productivity (excludes Inergi Renegotiation for IT and Corporate cost reductions)</td><td>($8.7M)</td><td>($63.7M)</td><td rowspan="2">($17.3M)</td></tr>
<tr><td>Sustained Productivity (Inergi Renegotiation)</td><td>($6.4M)</td><td></td></tr>
</table>

**Relative to 2018 Actuals*

Witness: Joel Jodoin, Bruno Jesus

OEB INTERROGATORY #186

Reference:

F-01-01 p.4

Interrogatory:

At the above reference the following is stated:

The proposed budget in the 2020 test year is $13.6 million more compared to the 2019 bridge year, but it is in-line with average historical levels. This increase is necessary to meet the legislated deadlines associated with the PCB program, fund planned transformer overhauls, support previously deferred preventative maintenance for station assets, and to address the backlog in overhead lines and component inspections and assessments. As highlighted earlier, the 2019 bridge year forecast for Sustainment OM&A is lower than historical levels partially as a result of a one-time extension of Hydro One's planned asset maintenance cycles. This includes fewer planned demand and corrective expenditures, extension of the PCB testing and retrofill program, deferral of overhead transmission line preventive maintenance and deferral of vegetation management on select 115kV circuits.

a) Please explain why the "previously deferred preventative maintenance for station assets" and the addressing of the "backlog in overhead lines and component inspections and assessments" is appropriate to be reflected in the 2020 test year, when Hydro One made a decision to defer these items in 2019.

Response:

a) As mentioned in Exhibit A-03-01, the 2019 OM&A expenditures are lower than the proposed test year OM&A as a result of the need to align to the funding envelope approved in Hydro One's 2019 transmission revenue cap adjustment application (EB-2018-0130). 2019 was a one-time reduction and such the funding level is not sustainable over the long term. As mentioned in F-01-03, Hydro One requires funding that is in line with its historical levels in order to maintain safety and reliability as well as to sustain its asset condition over the planning period. Continued funding at the 2019 level, or a reduction below the 2020 forecast amount, will pose unreasonable safety and reliability risks, which will adversely affect Hydro One's ability to meet its customer needs and priorities.

Witness: Donna Jablonsky

OEB INTERROGATORY #187

Reference:

A-03-01 p.41-42 Table 9

Interrogatory:

At the above reference the following is stated:

The "Plan" values shown in Table 9 at an individual investment category level for the historical and bridge years reflect the funding levels previously proposed by Hydro One in applications to the OEB for the applicable years. Values at the category level have not been adjusted in response to reductions to the overall OM&A expenditure levels approved in the applicable OEB decisions as the OEB's findings were at an envelope level. As such, OEB-reductions are included as a separate line item under "Adjustments" and are reflected in the total transmission OM&A "Plan" values at envelope level for the historical and bridge years. For further details, please see Exhibit F, Tab 1, Schedule 1.

a) Please provide further explanation as to why the envelope adjustments that occurred in the 2015, 2016, 2017, and 2018 historical years could not be applied to the main components of OM&A in Table 9.

Response:

a) As indicated in Exhibit A, Tab 3, Schedule 1 (Executive Summary) and further detailed in Exhibit F, Tab 1, Schedule 1 (Summary of OM&A) these adjustments reflect the EB-2014-0140 OEB-approved settlement reduction in OM&A and EB-2016-0160 OEB decision reduction in OM&A, B2M LP expenses which were removed as part of the proceeding and the pension adjustment which resulted in OM&A reduction to reflect pension plan's operating expense reduction. For example, EB-2016-0160 overall reductions are consistent with evidence that was produced throughout the proceeding. Moreover, this is consistent with the fact that the OEB approves OM&A costs at the envelope levels and all reductions were provided at an envelope level.

OEB INTERROGATORY #188

Reference:

F-01-06 p.2, Table 1 p.7

Interrogatory:

At the first reference above, Customer Care OM&A is shown as increasing from a 2018 "Plan" level of $3.9 million to an "Actual" level of $11.0 million

At the second reference above, the following is stated:

Over the 2015 to 2018 period, Customer Care OM&A expenditures trended upwards mainly due to the increased focus on large transmission customers, as well as increased costs related to detailed customer surveys which were centralized and included in this category level.

a) Please explain the differential between the 2018 "Plan" and "Actual" levels noted above

b) Please provide further explanation as to why an increased focus on large transmission customers, as well as customer surveys, as discussed in the second reference caused Customer Care OM&A expenditures to trend upwards over the 2015 to 2018 period.

Response:

a) A section of Corporate Affairs, which dealt largely with customer surveys, was reorganized into the Customer Service department.

b) The department that was added to Customer Service focused primarily on large transmission customers and customer surveys. The addition of this department to Customer Service resulted in additional costs for Customer Service, with offsetting reductions in Corporate Affairs. Additional reductions have been achieved in Corporate Affairs as a result of efforts to contain Outsourcing costs.

OEB INTERROGATORY #189

Reference:
A-03-01 p.40, F-02-02 p.15

Interrogatory:
At the first reference above, the following is stated:

Higher costs in 2018 and forecasted for 2019 and 2020 are due to a renewed investment in human resources talent. In order to meet new demands and greater expectations for human resource products and services, Hydro One has recruited additional external resources that will enable the function to deliver on what is needed to support the execution of the overall business strategy.

At the second reference above, the following is stated:

… OM&A reductions will be achieved through operating efficiencies, particularly the management of maintenance cycles, and a company-wide exercise undertaken by Hydro One to review and reduce corporate common costs. The review resulted in a significant commitment by business units to reduce corporate costs across the organization. These reductions were achieved primarily through a reduction in vacancies and by limiting consulting and contract engagements to critical functions, which also assist in strengthening and building internal capabilities.

a) Please reconcile Hydro One's statement in the first reference that it has "recruited additional external resources" with its statement in the second reference that it is "limiting consulting and contract engagements to critical functions."

Response:
a) The Human Resources team has increased in size in part to consolidate HR related functions from other teams outside of HR (with the corresponding decreases in headcount by the transferring function) and to provide enhanced programs to support the business (for further details see Exhibit I-10-VECC 40). Some of these programs include alignment of the compensation, performance management, HR operations and change management functions, as well as staff for the technology projects related to HR transformation.

Witness: Sabrin Lila

By hiring experienced talent externally, the Human Resources team has been able to leverage best practices from other organizations and reduce consulting fees. Externally hired talent brings expertise in some areas in which Hydro One would have previously required consulting expertise. This model allows Hydro One to implement new programs while developing internal resources and maintaining knowledge in-house.

OEB INTERROGATORY #190

Reference:

F-02-02 p.35

Interrogatory:

At the above reference, the following is stated:

Capitalized overheads represent the portion of allocated Common Corporate and/or business unit functions and services that support capital work. These costs are included in Common Corporate services and the budgets of other lines of business. OM&A expenses are thus reduced by the capitalized amounts.

Capitalized OM&A costs are charged to capital work based on a capital overhead rate derived from the allocation and capitalization studies performed by Black & Veatch, as described in Exhibit C, Tab 8, Schedule 2. As the capital work program increases, more overheads are capitalized.

It is OEB staff's understanding from the above that both the OM&A and capital components to Common Corporate Costs and Other Costs are recorded in Hydro One's OM&A. A calculation is then performed to remove the amounts that should be capitalized and a reduction is made to Common Corporate Costs and Other Costs through the line item "Other OM&A", representing a credit to OM&A.

a) Please state whether OEB staff's understanding is correct. If this is not the case, please explain.

b) If OEB staff's understanding is correct, please explain why the amounts recorded in Common Corporate Costs and Other Costs reflect a two-step process (i.e. step #1 record all costs and step #2 remove capitalized components), rather than simply recording directly only the amounts related to OM&A in one step.

Response:

a) Confirmed, the understanding is correct.

b) The two step process is required since employees that work in corporate functions do not directly charge their time to specific programs or projects. As a result, they are subject to the corporate capitalization process. The two step process allows the Company to track costs for each corporate group at a gross level, and apply the Black & Veatch methodology, as discussed in C-08-02-01. Overhead capitalization rate is monitored and forecasted throughout the year based on actual capital and OM&A spending to ensure compliance with the Black & Veatch methodology mentioned above.

OEB INTERROGATORY #191

Reference:
F-02-01 p.2 Table 2

Interrogatory:
At the above noted reference, the 2020 "Other OM&A" credit balance of $138.1 million is shown as an offset to the 2020 balance of $30.3 million. As well, a footnote to this table shows that OEB-directed reductions for compensation are reflected in this line item, including the 2017 and 2018 pension adjustment.

a) Please normalize the 2018 plan amount for "Other OM&A" to reflect the removal of "OEB-directed reductions for compensation" and show the percentage change when compared to the 2020 amount of "Other OM&A". Please provide an explanation for the change between the 2020 amount and the normalized 2018 plan amount.

Response:
a) Hydro One would like to note that the footnote to Table 2 in Exhibit F, Tab 2, Schedule 1 incorrectly states that OEB directed reductions are included in this line item (Other OM&A). The OEB directed adjustments are reflected under the 'Adjustments' section in Exhibit F, Tab 1, Schedule 1 Table 1. Further breakdown of the change between the 2020 Test Year amount for "Other OM&A" and the 2018 Plan amount can be found on Table 15 within Exhibit F, Tab 2, Schedule 2, Page 35.

Witness: Joel Jodoin

OEB INTERROGATORY #192

Reference:

F-01-03 p.10 Table 3, F-02-02 p.35 Table 15

Interrogatory:

At the first reference above, Table 15, which is entitled "Transmission Other OM&A" includes a category "Environmental Provision" which shows a credit balance of $12.6 million. This is a $2.6 million increase in the credit balance from the 2018 Plan level or a 26.0% increase to $12.6 million in 2020.

At the second reference above, Table 3, which is entitled "Environmental Management OM&A," the balance for 2020 is $22.1 million.

a) Please explain the difference between these two numbers.

Response:

a) The environmental provision is the forecasted liability on the balance sheet for the present value of the future estimated environmental expenditures strictly relating to work for PCB (polychlorinated biphenyls) and LAR (land assessment and remediation) programs, and only relates to remediation activities.

   The PCB costs are a subset of the "Environmental Management OM&A" budget; F-01-03, Table 3. The "Land Assessment and Remediation" budget is separately identified in reference F-01-03, Table 2.

OEB INTERROGATORY #193

Reference:

F-02-06 p.4 Table 3, F-02-06-01

Interrogatory:

a) Please explain how the amounts in the “Transmission” column of Table 3 are derived.

b) Please state whether any updates to the 2019 Black & Veatch Report would need to be made to reflect the impact of the following two subsequent events:

  a. Bill 2 and the February 21, 2019 Directive
  b. EB-2017-0049 Hydro One Distribution Decision and Order March 7, 2019

c) Please describe the updates made to the 2019 Black & Veatch Report since the last report was issued December 21, 2016, and state whether any of these changes would materially impact the 2020 revenue requirement.

Response:

a) The allocation to transmission CCF&S costs are derived through Hydro One’s corporate cost allocation methodology which has been reviewed by Black and Veatch. The referenced Table 3 has been provided to reconcile the figures discussed in the Black and Veatch review (see page 9 of F-02-06-01) to the allocation of Transmission CCF&S costs presented in Table 2 of F-02-06.

   The allocation methodology and subsequent review by Black and Veatch is discussed in detail in Exhibit F, Tab 2, Schedule 6 Attachment 1. This exhibit outlines each step and review to allocate corporate costs to Transmission and other subsidiaries.

b) Hydro One has incorporated the impact of Bill 2 in the filing which is confirmed in Exhibit F, Tab 2, Schedule 3 pages 2-3. The subsequent directive has affected costs allocated to Board and Chair as well as executive (non-ELT) escalation. Hydro One has noted the impact in Exhibit A, Tab 3, Schedule 1 and has accounted for these changes in the Blue Page update to this application. Full discussion is provided in Exhibit F, Tab 1, Schedule 1 pages 34-36.

c) The Black and Veatch methodology is materially consistent with that of prior applications. Specific considerations made in this study were related to Non-Regulated cost allocations and Bill 2. Please see Exhibit I, Tab 01, Schedule OEB-143 for further analysis on changes between historical studies. There was no material impact to revenue requirement as the majority of these costs were already allocated to Shareholder in Revenue Requirement.

OEB INTERROGATORY #194

Reference:
F-04-01 p.5

Interrogatory:
At the above noted reference, the following is stated:

Contract staff are individuals engaged as independent contractors, and are not on Hydro One's payroll. Contract staff are retained for their particular skill sets on projects, or to perform other work that is not of an ongoing nature. They are engaged by Hydro One for varying amounts of time and paid varying wages commensurate with their skill sets and the market rate for that skill. Contract staff are tracked by work programs or activities and not by headcount. Where applicable, the use of contract staff is governed by the terms of the collective agreements between Hydro One and its respective unions.

a) Please confirm that Contract Staff are not included in Hydro One's overall headcount.

b) Please provide the Contract Staff data as tracked by work programs and activities.

c) Please provide data to indicate how much Hydro One is spending on Contract Staff. If the data is not available, please explain why not.

d) How does Hydro One ensure that it is paying Contract Staff market rates for the skills procured?

e) What percentage of Contract Staff are former employees of Hydro One?

Response:
a) Confirmed.

b) The requested data would encompass hundreds of projects and work programs. In order to provide useful data, the table below captures contract spend by organizational units for 2016, 2017 and 2018.

LOB	2016	2017	2018	Grand Total
CORP FUNCTIONS & SRVCS	1,820,450	928,236	1,880,701	4,629,387
CUSTOMER CARE SERVICES	1,683,752	1,364,661	1,867,645	4,916,058
HUMAN RESOURCES	214,875	36,000		250,875
INFO SOLUTIONS DIVISION	29,440,103	20,124,870	19,759,660	69,324,633
OPERATIONS	283,574	300,691	1,904,745	2,489,010
PLANNING	725,320	1,075,914	359,442	2,160,676
SMART GRID	3,280,199	3,293,787	6,161,645	12,735,631
STRATEGY & CONSERV	921,229	884,044	513,857	2,319,129
Grand Total	**38,369,502**	**28,008,203**	**32,447,695**	**98,825,399**

c) Please refer to the table above in part b).

d) Hydro One runs competitive processes and negotiates the rates with the vendor. They are in line with market rates.

e) Hydro One's human resource information system cannot cross reference those who are employed as contract staff. There is an existing human resource policy that does require managers who intend to hire a former Hydro One employee to obtain senior level management approval prior to hiring the former employee as a contractor.

OEB INTERROGATORY #195

Reference:
F-04-01 p.13

Interrogatory:
At the above noted reference, Hydro One has provided "Table 2: Full Time Equivalents (FTE), 2017 to 2022."

OEB staff notes that the Total Regular FTEs for 2017 in this table are listed at 5,726 FTEs. However, OEB staff notes that when the FTE components in this table for 2017 are added together, the Total Regular FTEs for 2017 is 5,304 FTEs.

a) Please comment on this discrepancy and if necessary, update "Table 2: Full Time Equivalents (FTE), 2017 to 2022" with the correct amount of Total Regular FTEs for 2017.

Response:
a) As noted by OEB staff, "Table 2: Full Time Equivalents (FTE), 2017 to 2022", should read 5,304 Total Regular FTEs in 2017. The revised table is reproduced below:

		2017	2018	2019	2020	2021	2022
Regular	MCP	633	638	692	693	694	694
	Society	1,289	1,337	1,577	1,565	1,566	1,560
	PWU	3,382	3,527	3,739	3,790	3,824	3,852
	Total Regular	**5,304**	**5,502**	**6,008**	**6,048**	**6,084**	**6,106**
Temporar	MCP	18	22	6	6	6	6
	Society	36	28	13	12	9	9
	PWU	194	173	99	98	98	98
	Total Temporary	**248**	**223**	**118**	**116**	**113**	**113**
Casual	PWU Hiring Hall	1,230	1,351	1,794	1,717	1,781	1,782
	Casual Trades	1,364	1,353	1,296	1,265	1,205	1,159
	Total Casual	**2,594**	**2,704**	**3,090**	**2,982**	**2,986**	**2,941**
	Grand Total	**8,146**	**8,429**	**9,216**	**9,146**	**9,183**	**9,160**

Witness: Sabrin Lila

OEB INTERROGATORY #196

Reference:
F-04-01 p.13

Interrogatory:
At the above noted reference, Hydro One has provided "Table 2: Full Time Equivalents (FTE), 2017 to 2022."

Hydro One stated that Table 2 illustrates the historical (2017 and 2018) and forecasted (2019-2022) FTEs. Hydro One indicated that total regular and non-regular FTEs increase over this period primarily due to seven items which were listed.

a) Please quantify the impact between 2017 and 2022 on total FTEs and total compensation for each of the seven items. Please separate the impact between Transmission, Distribution, and Other.

Response:
a)

The major FTE changes between 2017 and 2018 are:

- The repatriated Customer Contact Centre resulted in 410 (280 regular employees and 130 non-regulars based on average headcount) incremental headcount in 2018 relative to 2017.
- Great Lakes Power Transmission LP resulted in 32 FTEs joining Hydro One Networks in 2018.

The following table quantifies the changes related to the seven items between 2018 actuals and 2019 FTE forecast and 2022 relative to 2019. This table accounts for 99% of the FTE change between 2018 actuals and 2019 FTE forecast. The remaining changes are increases and decreases with other functions. The total compensation cost is outlined in F-04-01-05.

FTE Change by Items listed below F-04-01 Table 2			
	Supports either Transmission, Distribution or both	**2019**	**2022**
Repatriated Customer Call Centre (1)	Dx	-8	-
Shared Service **Supply Chain Strategic Plan (2)** **Fleet Mechanics apprentices (6)** **Helicopter Services (7)**	Both	75	13
Distribution Work Program (4)	Dx	415	131
Transmission Work Program (3)	Tx	200	-165
Health & Safety (7)	Both	28	-3
Great Lakes Power (Hydro One Sault Saint Marie) (5)	Tx	-	-
Total		**710**	**-24**

The numbers beside each line item in the table above correspond with the explanatory bullet in Exhibit F, Tab 4, Schedule 1 page 13-14. Stronger health and safety focus within Helicopter Services is one of the initiatives related to Health & Safety.

OEB INTERROGATORY #197

Reference:
F-04-01
(1) p.23
(2) p.24
(3) p.38

Interrogatory:
Hydro One stated the following at the above noted first reference:

…The 2017 Mercer Total Compensation Study described in greater detail in Section 7.7.3 of this Exhibit shows that MCP total compensation is positioned 1% above market median…

However, at the above noted second reference, "Table 4: Willis Towers Watson, Salary Structure Positioning to Market Median" shows that "Target Total Direct Compensation" is 3% above the market median on an "Overall" basis.

At the third reference, the following table is shown – "Table 8: Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median." This shows that overall compensation (Management, Society, PWU) is 12% above the market median.

a) Please explain the difference between the first reference, which states that total compensation is positioned 1% above market median, and the second reference which shows a level of 3% above market median.

b) Please explain to what extent Hydro One is making efforts to bring its compensation more in line with the comparators.

c) Please provide a list of all types of compensation (i.e. salary, overtime, share grant, LTIP, etc.) that were paid in 2018 that: i) were included in the study, and ii) were not included in the study.

d) Are there any additional types of compensation (e.g. lump sum payments) that will be paid in 2020 that were not in 2018?

Response:

a) Variations in positioning relative to market median (1% v. 3%) are due to the fact that comparisons are being made to distinct compensation studies:

- Compensation positioning is 1% above market median relative to the results of the Mercer Compensation Benchmarking Study Results vs. Market Median (Exhibit F, Tab 4, Schedule 1 Table 8).
- Compensation positioning is 3% above market median relative to the results of the Willis Towers Watson, Salary Structure Positioning to Market Median (Exhibit F, Tab 4, Schedule 1 Table 4).

b) Hydro One remains committed to the ongoing review of its compensation programs to ensure they are equitable, sustainable and reflect competitive practices. These efforts have resulted in -5% positioning change relative to market from 2008 to 2017 as evident from the Mercer Survey results (Exhibit F, Tab 4, Schedule 1 Table 8).

In order to ensure continued alignment with the desired market median compensation positioning, Hydro One has planned or undertaken several initiatives:

- Regularly benchmark the compensation levels relative to the external market to assess competitiveness. The results of these studies are used to inform future compensation decisions, labour negotiations and potential program revisions.
- Continue to engage with union counterparts on a variety of committees and initiatives to assist in identifying opportunities to improve and modernize the compensation programs. For example, as an outcome of the most recent round of bargaining with the Society of United Professionals, a committee was formed between management and the union with a mandate to review compensation programs and propose potential improvements.
- Engage with third party independent experts to provide guidance on industry best practices and compensation.
- Hydro One has taken various steps to reduce pension costs as detailed in the "Pensions and Other Post Employment Benefit Costs" section (Exhibit F, Tab 4, Schedule 1 pages 38 to 41).

c) The table below outlines the elements of compensation included in the referenced compensation surveys:

	Compensation Study	
	Willis Towers Watson (F-04-01 Table 4)	**Mercer (F-04-01 Table 8)**
Base Salary	✓	✓
Short-term Incentives	✓ (based on target opportunity)	✓ (based on actual award)
Long-term Incentives	✓ (including share grants)	✓ (including share grants)
Pension & Benefits	X	✓ (relative value)
Overtime*	X	X

**Overtime is typically not included in compensation studies, as this information is highly dependent on usage – which may vary significantly by role and individual -and may not reflect the underlying competitive level of compensation.*

d) No, there are no new forms of compensation planned for 2020 that were not provided in 2018.

OEB INTERROGATORY #198

Reference:
F-04-01 p.32

Interrogatory:
Hydro One stated the following at the above noted first reference:

Consistent with the OEB's findings in EB-2016-0160 and the compensation evidence filed in Hydro One's 2018-2022 Distribution Custom IR application (EB-2017-0049), Attachment 5 to this Exhibit provides actual total compensation cost for Hydro One Networks and for both the distribution and transmission businesses for 2014 to 2018 and forecast total compensation cost for the years 2019 to 2022. While the Transmission work program is growing by approximately 26% between 2019 and 2022, Transmission related compensation costs are growing by only 12% or 4% per annum.

a) Please provide a detailed explanation as to how with the transmission work program growing by 26% between 2019 and 2022, transmission related compensation costs are growing by only 12%. Please include in the discussion any impacts of changes in allocations between the transmission and distribution operations of Hydro One, as well as overhead allocations from OM&A to the capital program.

Response:
a) As outline in Exhibit F, Tab 4, Schedule 1 pages 11 – 12 and Exhibit B, Tab 2, Schedule 1 pages 3 – 4, Hydro One has resource flexibility by utilizing a variety of labour resources including regular, temporary, PWU Hiring Hall, direct-hire casual building trades and qualified service providers.

   Hydro One intends to leverage a variety of these labour resourcing options for the 2019 to 2022 period, with a particular emphasis on contracting work and utilization of the direct-hire casual workforce. For contracted work, Hydro One will leverage its qualified third party construction partners to augment its direct-hire casual trades workforce. The plan is to maintain the current capacity within Transmission Lines and Stations Construction divisions to complete complex work and utilize contractors to rapidly scale to deliver its growing capital work program. In addition, Hydro One will continue to engage contractors to complete its non-core work where it does not have the internal capabilities such as major buildings and high-voltage underground cable installations. Hydro One will focus on contracting low-risk greenfield station and line construction projects and areas of work that are increasing rapidly such as transmission lines sustainment projects.

The use of the casual workforce is a fiscally prudent way of managing the work program as the total compensation package is less costly. It is also important to note that the 26% growth in the transmission work program also includes non-labour costs.

There has been no material shift in overhead allocation from the Distribution to Transmission business that would contribute to this increase.

OEB INTERROGATORY #199

Reference:
F-04-01 p.34-35

Interrogatory:
At the above noted reference, Hydro One describes how its requested executive compensation and board of director costs are in compliance with Bill 2 and the February 21, 2019 Directive.

a) Please confirm that no further adjustments to Hydro One's requested executive compensation and board of director costs are required to ensure compliance with Bill 2 and the February 21, 2019 Directive as well as the OEB's EB-2017-0049 Decision and Order.

Response:
Confirmed, all required adjustments have been incorporated as part of the original submission on March 21, 2019 and further adjusted as part of the blue-page update that was submitted on June 19th, 2019. Please refer to the updated Exhibit F, Tab 4, Schedule 1 pages 34-36.

Witness: Sabrin Lila

OEB INTERROGATORY #200

Reference:
F-01-01 p.7

Interrogatory:
At the above noted reference, Hydro One stated the following:

2018 actuals are lower than the 2018 plan and 2017 actual expenditure, mainly due lower Operations staff costs (i.e., lower pension burdens, adjustments based on average vacancy rates, and applied recoveries).

a) Please provide Hydro One's actual vacancy rate for each year between 2014 and 2018.

b) Please provide the forecast vacancy rate for 2020, and the basis for the forecast.

c) Please confirm that Hydro One has built into its budget for 2020 its forecast vacancy rate for 2020.

d) If (c) is confirmed, please explain how Hydro One has translated the forecast vacancy rate into a budgeted number.

e) If (c) is not, please explain why not.

Response:

a) Hydro One has not historically tracked vacancy rates. While Hydro One can determine a vacancy rate for Corporate groups, Hydro One's systems (Human Resource and Finance) do not support tracking monthly headcount, including vacancies, relative to budget headcount for field groups. For these organizations where vacancies occur, Hydro One is readily able to resource with the PWU hiring hall or staff augmentation.

b) The forecasted vacancy rate of 7% was used for 2020 planning of common corporate groups. The basis for the forecast was a three-year historical analysis of budget vs. actual headcount.

c) Confirmed.

d) As described in Exhibit F, Tab 2, Schedule 1, there were significant commitments made by business units to reduce corporate costs across the organization. The reductions were achieved primarily through a reduction in vacancies and limiting consulting contracts to critical functions, with an overall focus on building internal capabilities. In addition, Hydro One translated the forecasted vacancy rate into a budgeted number by applying a 7% labour cost reduction to corporate budgets.

e) Not applicable.

OEB INTERROGATORY #201

Reference:
F-01-07 p.4, TSP-01-06 p.7

Interrogatory:
At the above noted reference, Hydro One stated the following:

Hydro One's aim is to execute its annual O&M work strategy at a lower cost relative to historical costs through improved productivity…

At the above noted second reference, Hydro One stated that $22 million of OM&A productivity savings have been estimated for 2020.

a) Please confirm that the above $22 million of forecasted OM&A productivity savings have been incorporated into Hydro One's requested OM&A for 2020 of $375.8 million. If this is not the case, please explain.

b) Are the forecasted productivity savings a key factor in keeping the 2020 OM&A at the requested level of $375.8 million? Please explain.

Response:
a) Confirmed.

b) Achieving sustained productivity gains in OM&A is a key factor in keeping OM&A at the requested level. Key OM&A initiatives are related to IT Renegotiation, Corporate Cost Reductions, Wrench Time Improvements and Tx Brush Control.

   These initiatives are discussed further in the TSP Section 1.6. Hydro One has embedded the OM&A productivity savings forecast into the business plan supporting this filing application and in the compensation scorecards. As a result, Hydro One bears the risk of achieving these savings with no risk being put on the ratepayer.

Witness: Joel Jodoin

OEB INTERROGATORY #202

Reference:

F-05-01 p.1-2
EB-2016-0160, Sept 27, 2017 Decision and Order p.81

Interrogatory:

At the first reference above, Hydro One has stated that it is proposing to recover its pension costs on a cash basis.

At the second reference above, the OEB ordered that if Hydro One proposes to continue using the cash method as the basis for recovering its pension costs beyond December 31, 2018, then in its next transmission revenue requirement proceeding, Hydro One must provide evidence that addresses the principles, practices and policy determinations in accordance with the provisions

In its September 14, 2017 Report on the Regulatory Treatment of Pension and OPEB costs (OEB Report), the OEB indicated that utilities proposing to set rates using a method other than accrual must support such a proposal with evidence, giving consideration to factors such as providing value to customers and assuring fairness to both present and future ratepayers, and the principles and practices enunciated in the OEB Report.

a) In accordance with the OEB Report, please provide evidence that supports the appropriateness of Hydro One's use of the cash method to recover its pension costs. Please ensure that the evidence provided addresses the required areas as specified in OEB Report.

b) In indicating that the cash method results in lower costs being recovered through rates, Hydro One, has not provided any analysis to support this statement. To that end, please prepare an analysis similar to the one provided for OPEBs in Table 3 of Exhibit F/Tab5/Schedule1, comparing on a historical basis, the cash amount recovered in rates and the accrual expense related to Hydro One's annual pension obligations.

Response:

a) The principles in the OEB Report support the use of the cash method if the accrual method does not result in just and reasonable rates, and if the cash method better provides value to customers and fairness to both present and future ratepayers. Maintaining the current cash method would be consistent with this, and provides stability and predictability. If Hydro One switched to the accrual method, the regulatory asset currently on its books would have to be recovered from ratepayers over a 10 to 15 year period thus negatively affecting both current and future ratepayers.

The chart in part b) below shows that over time, cash basis has provided a lower cost to ratepayers. As reflected below, there can be fluctuations from year to year. However, on the whole, the ratepayers have incurred a lower cost under the cash basis. The administrative burden of switching back and forth would be detrimental and therefore Hydro One supports the use of one method.

b)

Cash vs Accrual basis Pension Costs ($ Millions)

Pension	Pre 2013	2013	2014	2015	2016	2017	2018	2019	2020	Total
Amounts included in Tx rates										
OM&A	238	32	33	29	29	18	16	16	11	**422**
Capital	146	38	42	42	40	31	30	30	27	**426**
Total Cash Basis	**384**	**70**	**75**	**71**	**69**	**49**	**46**	**46**	**38**	**848**
Accrual method	486	133	77	73	51	43	35	18	13	**929**
Recovery of Reg Asset (1) (2)	0	0	0	0	0	0	0	0	16	**16**
Total Accrual Method	**486**	**133**	**77**	**73**	**51**	**43**	**35**	**18**	**29**	**945**
Cash Basis less Accrual Basis	**(102)**	**(63)**	**(2)**	**(2)**	**18**	**6**	**11**	**28**	**9**	**(97)**

(1) Represents recovery of the $547 million Pension Regulatory Asset at Dec 31, 2018, with an assumption that 45% of the Pension Regulatory Asset is attributable to Hydro One Transmission and is recovered over a period of 15 years.
(2) The amount of the Recovery changed from $29M to $16M for 2020 due to better than expected performance of the plan and a change in discount rates, both of which resulted in a reduction in the unfunded pension liability as at Dec 2018 compared to Dec 2017.

OEB INTERROGATORY #203

Reference:
F-05-01-01 p.15 of 61, F-05-01 Table 2

Interrogatory:
At the first reference above, Hydro One has provided the pension valuation that underpins the pension cash contributions for the bridge and test years.

At the second reference above, Hydro One has presented its pension contributions for 2020 in Table 2, broken out between capital and OM&A.

a) For the bridge year 2019, please confirm if Hydro One chose to take a pension contribution holiday and whether it filed the related cost certificate within the legislated deadline of the Pension Benefits Act

b) In Table 2 of Ex F-5-1, Hydro One presents total pension contributions for the combined company of $78 million. Please explain the discrepancy compared to the total pension contributions for 2020 as presented in Section 3 of the pension valuation ($69 million).

c) If $69 million is in fact the correct contribution amount, then please prepare Table 2 of Ex F-5-1 with the correct amounts and allocations between the Transmission and Distribution businesses.

d) As part of the current application, Hydro One has capitalized amounts related to pension costs for the years 2021 and 2022. Please provide the amount of pension costs being capitalized for each of these years.

e) Please explain what underpins the pension costs being capitalized for those years. If they are an estimate, please explain the basis for this estimate.

f) Please explain where the variance is captured between what Hydro One proposes as the capital component of its pension costs compared to what it actually capitalizes in respect to its pension costs.

Response:

a) Hydro One filed a cost certificate for 2019 within the legislated deadline of the *Pension Benefits Act* to preserve its right to take a pension contribution holiday for the second part of 2019 as permitted under the legislation. A copy of the cost certificate is included as Attachment 1 to this interrogatory response. Since then, Hydro One received a letter from the Financial Services Regulatory Authority ("FSRA") dated July 17, 2019 confirming that the post-May 1 Rules (as defined in the evidence) will apply to Hydro One retroactively to March 1, 2018 ("FSRA Letter") once FSRA approves the Inergi Transfer (as defined in the evidence). The FSRA Letter is included as Attachment 2 to this interrogatory response.

   Under the post-May 1 Rules, a private employer such as Hydro One may only take a contribution holiday in a year if an actuary certifies the plan has a funded ratio of at least 105% calculated on a wind-up basis. Provided the Inergi Transfer is approved by FSRA as anticipated, barring extraordinary circumstances such as the Hydro One Pension Plan assets experiencing at minimum a 56% investment return over two years, Hydro One will not be legally permitted to take a contribution holiday in any of 2020, 2021 or 2022, notwithstanding the fact that it filed a cost certificate for 2019. Please see the Eckler Report dated August 1, 2019, included as Attachment 3 to this interrogatory response for more details.

b) Table 2 of Ex F-5-1 presents total pension contributions for the company of $78 million. This is based on a forecast provided by the actuaries in mid-December of 2017. The Actuarial Valuation is as at December 31, 2017 and was filed April 30, 2018. The difference between the $69 million noted in the valuation and the $78 million forecast contributions presented in Table 2 of Ex F-5-1 is that the valuation is based on actual plan headcount as at December 31, 2017 whereas the forecast amount of $78 million accounts for future entrants into the plan, particularly the Customer Service Operations (CSO) or call-center employees (as described in Exhibit F, Tab 5, Schedule 1 page 5), which would have an impact on the 2020 pension contributions among other updated assumptions. Any variance between the OM&A portion of the forecast pension contributions included in rates and the actual pension contributions will be captured in the pension cost variance account. Please refer to part f) below for discussion on variances in relation to the capital portion.

c) Hydro One believes that the $78 million represents the appropriate amount of pension costs for 2020 based on the latest information available. Please see response to part b) above.

d) As part of the current application, pension costs capitalized in 2021 for Hydro One Transmission: $29 million, based on total consolidated capitalized pension costs of $48 million for Transmission and Distribution.

As part of the current application, pension costs capitalized in 2022 for Hydro One Transmission: $29 million, based on total consolidated capitalized pension costs of $50 million for Transmission and Distribution.

e) Capitalization of pension costs is based on the forecasted labour cost attributable to capital based on the forecasted work program for that year.

f) In respect to the variance between what Hydro One proposes as the capital component of its costs and subsequently what becomes the approved capitalized amount in rates, compared to what it actually capitalizes in respect to its pension costs is not currently tracked as part of a separate variance account. Unlike the OM&A component which has an established account, the capital component would be in essence captured as part of the Cumulative In-Service Variance Account (CISVA).

Moreover, as Hydro One earns a return on capital vs. OM&A which is recovered as expenses incurred capital related variances would not have a material impact on revenue requirement. Additionally, when it is time to rebase, the revenue requirement is calculated based on actual rate base and would reflect actual capitalized amounts of pension.

Lastly, Hydro One notes that currently, it does not have any established accounts that track capital related variances between OEB approved amounts in rates and actual amounts spent.

Hydro One Inc.

Hydro One Pension Plan

Actuarial Cost Certificate as at January 1, 2019

Registration Number: 1059104

This actuarial cost certificate has been prepared for Hydro One Inc. with respect to the Hydro One Pension Plan (the "Plan"), and is intended to satisfy the requirements of section 7 of the Regulation to the *Pension Benefits Act (Ontario).*

The most recent actuarial valuation of the Plan was prepared as at December 31, 2017. The corresponding report, dated April 30, 2018, disclosed a surplus on both a going concern and solvency basis, and that the amount of the going concern surplus is sufficient to meet the expected normal actuarial cost for the period covered by the report. The remainder of this certificate will refer to this report as the "Funding Report". In addition to the Funding Report, an asset transfer report was prepared as at March 1, 2018 and was filed in November 2018. As of the date of this actuarial cost certificate, regulatory approval of asset transfer report is still pending.

The purpose of this actuarial cost certificate as at January 1, 2019 is to determine the maximum amount of actuarial surplus identified in the Funding Report that can be applied to reduce contributions for the employer normal actuarial cost in respect of the Plan year beginning on January 1, 2019. This determination is necessary under section 7(3.1) of the Regulation to the *Pension Benefits Act (Ontario)*.

Plan Provisions

This actuarial cost certificate is based on the provisions of the Plan in effect at January 1, 2019. A summary of these provisions can be found in Appendix F of the Funding Report.

Membership Data

This actuarial cost certificate is based on the membership data supplied by Hydro One Inc.'s third-party administrator, Morneau Shepell, as at January 1, 2019. A summary of the data can be found in Appendix A. Elements of the data review are similar to those described in Appendix E of the Funding Report.

Assets

The data relating to the invested assets are based on the draft financial statements issued by KPMG. Appendix B contains further details related to the invested assets and development of the actuarial value of assets.

Actuarial Assumptions and Methods

The going concern, solvency, and hypothetical windup actuarial assumptions and methods used for the purpose of this actuarial cost certificate are the same as those summarized in Appendix C and Appendix D of the Funding report, with the following exceptions:

- For going concern liabilities and normal actuarial cost, the discount rate is 5.60% p.a. The assumption is an estimate of the expected long-term return on plan assets as at January 1, 2019 adjusted as follows:

▪ Expected long-term return on plan assets before adjustments	6.07%
▪ Investment management fees	(0.04)%
▪ Adjustment for non-investment expenses paid by the plan	(0.07)%
▪ Margin for adverse deviations	(0.40)%
▪ Rounding effect (discount rate is rounded to 10 basis points)	0.04%
▪ Expected long-term return on plan assets after adjustments and margin	5.60%

- For going concern liabilities and normal cost, the salary scale for members of the Powers Workers Union was adjusted to reflect an increase of 1.5% p.a. (plus merit and promotion) for 2019 and 2020 as per the terms of current collective bargaining agreement.

- For solvency and windup liabilities assumed to be settled via annuity purchase, the discount rates are:
  - Non indexed: 3.20% p.a.
  - Fully-indexed: 0.08% p.a.
  - Partially-indexed: 0.85% p.a.

  These assumptions correspond to an approximation of the annuity purchase rates as at January 1, 2019 following consideration of the annuity purchase proxy guidance from the Canadian Institute of Actuaries for valuations with effective dates on and after December 31, 2018.

- For solvency and windup liabilities assumed to be settled via commuted value transfer, the discount rates are:
  - Non indexed: 2.80% p.a. for 10 years and 3.20% p.a. thereafter
  - Fully-indexed: 1.60% p.a. for 10 years and 1.70% p.a. thereafter
  - Partially-indexed: 1.90% p.a. for 10 years and 2.10% p.a. thereafter

  These assumptions have been determined in accordance with the *Standards of Practice for Pension Commuted Values* in effect at January 1, 2019.

- 2019 YMPE and Income Tax Act (ITA) limits have been reflected. For the solvency and windup liabilities, the ITA limit has been escalated at 1.09% p.a. for 10 years and 1.89% p.a. thereafter.

The Funding Report includes certain other disclosures relevant to this cost certificate, as required by actuarial standards of practice.

Calculation Results

The going concern and solvency results at January 1, 2019 and the estimated employer normal actuarial cost and member contributions for the ensuing year are provided below. Comparable figures as at December 31, 2017 from the Funding Report are also provided.

	January 1, 2019	*December 31, 2017*
Going Concern Financial Position		
Actuarial value of assets	$ 7,202,478,000	$ 6,932,459,000
Total going concern liability	6,095,036,898	6,120,630,269
Going concern surplus	$ 1,107,441,102	$ 811,828,731
Prior year credit balance	48,000,000	48,000,000
Going concern surplus after prior year credit balance	$ 1,059,441,102	$ 763,828,731
Solvency Financial Position		
Solvency value of assets [1]	$ 7,201,634,000	$ 7,298,522,000
Total solvency liability	6,564,444,397	6,547,705,910
Solvency surplus	$ 637,189,603	$ 750,816,090
Prior year credit balance	48,000,000	48,000,000
Solvency surplus after prior year credit balance	$ 589,189,603	$ 702,816,090
Estimated Normal Cost for Ensuing Year [2]		
Employer normal actuarial cost	$ 68,934,975	$ 70,892,448
Member contributions	$ 53,554,752	$ 49,552,747

Note:

[1] Reflects $7,000,000 of assumed windup expenses.

[2] Provided for the purpose of satisfying the requirements of section 7 of the Regulation to the Pension Benefits Act (Ontario). The employer normal actuarial cost and actuarial cost rule described in the Funding Report will be used to determine employer normal cost requirements.

The going concern surplus increased from $811,828,731 to $1,107,441,102 as a result of the following:

- $43,838,751 due to expected interest on the surplus;
- $132,768,855 due to investment experience;
- $(48,628,867) due to liability experience; and
- $167,633,632 due to changes in the going concern discount rate and salary scale.

The effect of decreasing the discount rate by 1% would result in the following as at January 1, 2019:

- an increase of $871,986,663 in the going concern liability;
- an increase of $958,236,557 in the solvency liability; and
- an increase of $37,451,248 in the total normal actuarial cost.

If the plan were to be wound up on January 1, 2019, the hypothetical windup value of assets would be equal to the solvency value of assets. As permitted by the Regulation to the *Pension Benefits Act (Ontario),* the employer has elected to exclude certain benefits from the solvency liability. The full hypothetical windup liability, taking into account all of the benefits excluded under the Regulation, is $9,823,719,689 as at January 1, 2019. The transfer ratio, as defined in the Regulation to the *Pension Benefits Act (Ontario)*, is 73%.

In accordance with section 7 of the Regulation to the *Pension Benefits Act (Ontario)*, the maximum amount of the surplus revealed in the December 31, 2017 valuation that may be applied to reduce contributions for the normal cost for the plan year commencing January 1, 2019 is $589,189,603. This amount has been determined as the lesser of the estimated going concern surplus and estimated solvency surplus at January 1, 2019, net of the prior year credit balance.

Actuarial Opinion

In our opinion, for the purpose of this actuarial cost certificate:

- the membership data on which the calculations are based are sufficient and reliable,
- the assumptions are appropriate, and
- the methods employed are appropriate.

This certificate has been prepared, and our opinion has been given, in accordance with accepted actuarial practice in Canada.

The calculations have been performed in accordance with our understanding of the funding and solvency standards prescribed by the *Pension Benefits Act (Ontario)* and Regulation thereto, and in conformity with the requirements of the *Income Tax Act (Canada)* and Regulation thereto.

To the best of our knowledge and on the basis of our discussions with Hydro One Inc., no events which would have a material impact on the results occurred between January 1, 2019 and the date this certificate was completed.

The results presented in this certificate have been developed using a particular set of actuarial assumptions and methods. Other results could have been developed by selecting different actuarial assumptions and methods. The results presented in this certificate are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events.

The information contained in this certificate was prepared for Hydro One Inc., for filing with the Financial Services Commission of Ontario.

Towers Watson Canada Inc.

Davis Gonsalves

Davis Gonsalves
Fellow of the Canadian Institute of Actuaries

Suzanne Jacques

Suzanne Jacques
Fellow of the Canadian Institute of Actuaries

June 7, 2019

Appendix A – Membership

Summary of Membership Data

	January 1, 2019
Active and disabled members	
▪ Number	5,599
▪ Average age	44.1
▪ Average credited service	12.1
▪ Average pensionable earnings	$ 105,362
Retired members and beneficiaries	
▪ Number	7,492
▪ Average age	74.0
▪ Average annual lifetime pension (excluding temporary pension amounts)	$ 41,125
Terminated vested members	
▪ Number	302
▪ Average age	53.7
▪ Average annual lifetime pension	$ 10,060

Appendix A – Membership

Membership Reconciliation

	Actives & Disabled Members	Terminated Vested Members	Retired Members & Beneficiaries	Total
As at December 31, 2017	5,308	305	7,449	13,062
■ New entrants (including re-employed)	299	0	0	299
■ Transfers from Inergi LP	272	0	0	272
■ Terminated (with lump sum payment)	(43)	(10)	0	(53)
■ Termination (vested pension entitlement)	(32)	32	0	0
■ Retirement	(200)	(23)	223	0
■ Deceased (with lump sum payment)	(3)	0	0	(3)
■ Deceased (without beneficiary)	0	0	(89)	(89)
■ Deceased (with beneficiary)	(2)	(1)	(189)	(192)
■ New beneficiaries (including ex-spouses)	0	0	95	95
■ Data corrections	0	(1)	3	2
■ Net change	291	(3)	43	331
As at January 1, 2019	5,599	302	7,492	13,393

Willis Towers Watson

Appendix B – Assets

Reconciliation of Invested Assets

Assets as at December 31, 2017			$	7,305,522,000
Receipts:				
■ Contributions:				
- Employer normal actuarial cost	$	75,042,000		
- Employer amortization payments		0		
- Member required contributions		52,525,000		
- Past service contributions		451,000		
- Provision for non-investment expenses		0	$	128,018,000
■ Investment return, net of investment expenses				161,011,000
■ Total receipts			$	289,029,000
Disbursements:				
■ Benefit payments:				
- Pension payments	$	(324,564,000)		
- Lump sum settlements		(34,403,000)		
- Other benefit payments		0	$	(358,967,000)
■ Non-investment expenses				(26,950,000)
■ Total disbursements			$	(385,917,000)
Assets as at January 1, 2019			$	7,208,634,000

Comments:

- This reconciliation is based on the draft financial statements issued by KPMG and certain cash flow information provided by Hydro One.
- The rate of return earned on the market value of assets, net of all expenses, from December 31, 2017 to January 1, 2019 is approximately 1.9%.

Appendix B – Assets

Development of Actuarial Value of Assets

	Adjusted Market Value Beginning from:				
	December 31, 2014	December 31, 2015	December 31, 2016	December 31, 2017	January 1, 2019
Adjusted market value as at December 31, 2014	$ 6,311,204,000				
Net cash flow for 2015	(117,373,000)				
Assumed investment return	362,695,000				
Adjusted market value as at December 31, 2015	6,556,526,000	$ 6,745,869,000			
Net cash flow for 2016	(182,014,000)	(182,014,000)			
Assumed investment return	349,203,000	359,427,000			
Adjusted market value as at December 31, 2016	6,723,715,000	6,923,282,000	$ 6,909,437,000		
Net cash flow for 2017	(235,047,000)	(235,047,000)	(235,047,000)		
Assumed investment return	350,209,000	360,786,000	360,052,000		
Adjusted market value as at December 31, 2017	6,838,877,000	7,049,021,000	7,034,442,000	$ 7,305,522,000	
Net cash flow for 2018	(230,949,000)	(230,949,000)	(230,949,000)	(230,949,000)	
Assumed investment return	363,146,000	374,493,000	373,706,000	388,345,000	
Adjusted market value as at January 1, 2019	$ 6,971,074,000	$ 7,192,565,000	$ 7,177,199,000	$ 7,462,918,000	$ 7,208,634,000
Actuarial Value of Assets					
Average of the five adjusted market values as at January 1, 2019					$ 7,202,478,000
Net outstanding amounts					0
Going concern value of assets as at January 1, 2019					$ 7,202,478,000

FSRA ARSF
Financial Services Regulatory Authority of Ontario
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July 17, 2019

Registration Number: 1059104

Ms. Lisa J. Mills
Brown Mills Klinck Prezioso LLP
130 Adelaide Street W.
Suite 1005, Box 17,
Richmond-Adelaide Centre
Toronto, ON M5H 3P5

Dear Ms. Mills:

Re: Hydro One Pension Plan (the "Plan")

Effective June 8, 2019, the Financial Services Regulatory Authority of Ontario (FSRA) has assumed the regulatory duties of the Financial Services Commission of Ontario and the Deposit Insurance Corporation of Ontario.

Thank you for your letter dated July 10, 2019, addressed to Ms. Caroline Blouin, Executive Vice President, Pensions, regarding the interpretation of the Ontario funding rules under the Pension Benefits Act (the "PBA") and Regulation 909 (the "Regulation") in respect of the impact of the Hydro One Pension Plan Asset Transfer Actuarial Valuation as at March 1, 2018 (Hydro One Asset Transfer Report) on the funding of the Plan. Your letter has been referred to me for a response.

We have set out below the interpretive issues as phrased in your July 10 letter with our responses:

Issue 1

The Hydro One Asset Transfer Report will be considered the "first report with a valuation date on or after December 31, 2017" for purposes of s.4(2)(a.1) of the PBA Regulations assuming the Application is approved prior to the filing of the next full actuarial valuation report for the Plan.

Our response: *Yes, the Hydro One Asset Transfer Report becomes operative on the effective date of the asset transfer, i.e., March 1, 2018, if the Asset Transfer Application is approved.*

Issue 2

Hydro One will be required to commence funding the Plan in accordance with the post-May 1, 2018 PBA funding rules, including the funding of the provision for adverse deviations (PfAD), retroactive to March 1, 2018.

Our response: *Yes, this is because the Hydro One Asset Transfer Report was filed after April 30, 2018 and prepared in accordance with the post-May 1, 2018 PBA funding rules.*

Issue 3

The Hydro One Asset Transfer Report will be considered "the last filed valuation" for purposes of section 6.3 of the PBA Regulations such that section 55.1 of the PBA will effectively apply to the Plan retroactive to March 1, 2018.

Our response: *Yes, section 55.1 of the PBA will apply to the Plan effective March 1, 2018 once the Asset Transfer Application is approved.*

Issue 4

Hydro One will only be permitted to take a contribution holiday on and after March 1, 2018 if the transfer ratio of the Plan is greater than 1.05.

Our response: Yes, if the Asset Transfer Application is approved, effective on March 1, 2018, *Hydro One is eligible to reduce or suspend contributions for normal cost and for the provision for adverse deviation in respect of normal cost only if the Plan has an available actuarial surplus and other prescribed conditions are met (section 55.1 of the PBA). An "available actuarial surplus" is defined in section 7.0.2 of the Regulation and, in part, requires a transfer ratio greater than 1.05.*

Issue 5

If Hydro One were to take a contribution holiday under the PBA Regulations prior to the approval of the Hydro One Asset Transfer Report, a true-up would be required once the Hydro One Asset Transfer Report is approved to reflect the requirement that contribution holidays on and after March 1, 2018 require the Plan to have a transfer ratio greater than 1.05.

Our response: *Yes, contribution obligations on and after March 1, 2018 would be determined under the Hydro One Asset Transfer Report, if it is approved.*

If at any time you have any questions or concerns, you may contact Mr. David Pahn, the Pension Officer assigned to the Plan at the address above, or directly by telephone at 416-226-7815, or toll free at 1-800-668-0128, extension 7815. Please reference Pension Division on your envelope and refer to the registration number shown at the top right-hand corner of this letter.

Yours truly,

Mark Eagles
Senior Manager, Pension Policy
FSRA

Copy: Robert Cultraro, Hydro One Inc.
Cassidy McFarlane, Hydro One Inc.
Suzanne Jacques, Willis Towers Watson
Gordon M. Nettleton, McCarthy Tétrault LLP
Caroline Blouin, FSRA
Ann Chow, FSRA
David Pahn, FSRA

ECKLER

EXPERT REPORT IN RESPECT OF PENSION ISSUES RELATED TO HYDRO ONE NETWORKS INC.

August 2019

Prepared by:

ECKLER

Simon J. Nelson, FSA, FCIA

Eckler Ltd.
5140 Yonge Street, Suite 1700
Toronto, Ontario
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ECKLER

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EXPERT REPORT IN RESPECT OF PENSION ISSUES RELATED TO HYDRO ONE NETWORKS INC.

Section 1. INTRODUCTION

Eckler Ltd. (**"Eckler"**) was retained by Hydro One Networks Inc. ("**HONI**"), through their counsel McCarthy Tétrault LLP ("**McCarthy**"), to provide an independent expert report ("**Report**") on certain pension issues, as they pertain to the period 2018-2022, as outlined in the Mandate section below.

I prepared this Report as an independent expert report under the Ontario Energy Board's Rules of Practice and Procedure Rule 13A. No limitations or constraints were put on me in preparing this Report. Appendix E contains our "acknowledgement of expert's duty" in the form set out by the Ontario Energy Board ("**OEB**").

Further to actuarial standards on the preparation of an expert witness report, we note that the users of the report may include the OEB and the public through the filing of this report with the OEB. I understand the Report may be used as evidence in proceedings before the OEB or in subsequent appeal proceedings by HONI. I further understand that I may be required to appear before the OEB and address questions regarding the content of the Report through cross-examination.

MANDATE

In this Report, I have been asked to provide my expert opinion on the following pension issues as they pertain to the period 2018-2022:

- The effects on HONI's contribution holiday permissibility, following FSRA's determination of a March 1, 2018 effective date for the transfer of pension assets and liabilities in relation to the in-sourcing of call centre functions from Inergi LP and Vertex Customer Management (Canada) Ltd. to Hydro One.

- The likelihood of HONI being able to take a contribution holiday during the 2018-2022 period as a result of the transfer ratio of the Plan increasing to more than 105%.

- The general effect of the Post-May 2018 Rules on contribution holidays and contribution stability practices. In addition, whether the permissibility of a contribution holiday should necessarily result in a plan sponsor utilizing this contribution holiday, as it relates to risk management and general governance principles, and whether this has changed following the enactment of the Post-May 2018 Rules.

- The permissibility and general practices around filing (or not filing) a cost certificate for a contribution holiday in a year where a full valuation report is also to be filed.

- The impact of the amendments to O. Reg. 909 under the Pension Benefits Act ("**PBA**") effective May 1, 2018 ("**Post-May 2018 Rules**"), as it relates to:
    - Observed changes in Financial Services Commission of Ontario ("**FSCO**") or Financial Services Regulatory Authority of Ontario ("**FSRA**") practices towards contribution holidays and associated actuarial filings.
    - The level of uncertainty for pension plan stakeholders and service providers around the interpretation and practical effect of the Post-May 2018 Rules following their announcement, particularly during the period before FSCO/FSRA published Q&As/guidelines in August 2018 and additional clarifying amendments were made to O. Reg 909 on May 21, 2019.
    - The reasonableness of HONI's response to this uncertainty, as it pertains to actuarial filings and contribution holidays.

Section 2. QUALIFICATIONS

I have prepared this report in my capacity as an actuarial consultant advising pension and employee benefit plan sponsors and employee groups for 21 years with respect to all aspects of pension plan administration, design, funding and accounting for registered pension, supplemental pension and employee benefit plans. I am a Fellow of the Society of Actuaries (FSA) and a Fellow of the Canadian Institute of Actuaries (FCIA).

I have been employed for 6 years by, and am a Principal of, Eckler Ltd., an actuarial consulting firm. I am currently the co-leader of the pension actuarial practice for the Toronto-Halifax-Winnipeg-Vancouver offices of Eckler Ltd.

In my professional capacity, I currently serve as a member of the Actuarial Standards Board (ASB), as a member of the Pension Advisory Committee of the Canadian Institute of Actuaries (CIA) and as a member of the National Policy Committee of the Association of Canadian Pension Management (ACPM). I am also a past chair of the CIA's Committee on Pension Plan Financial Reporting (PPFRC).

My cirruculum vitae is attached as Appendix A.

Section 3. BACKGROUND

This Section 3 provides a brief chronology of some of the key legislative and regulatory background events relevant to the issues further discussed in Section 4. This chronology is not intended to be exhaustive.

- May 19, 2017: Ontario government announces that it will be implementing a new funding framework for defined benefit pension plans.
- December 14, 2017: Ontario releases a consultation on the Reform of Ontario's Funding Rules for Defined Benefit Pension Plans: Description of New Funding Rules. This consulation provides a description of proposed regulations relating to the province's new funding framework for defined benefit pension plans.
- March 1, 2018: Effective date of the asset transfer related to the assets and liabilities of Inergi LP and Vertex Customer Management (Canada) Ltd. to HONI. ("**Asset Transfer**").
- April 20, 2018: O. Reg. 250/18, which amends O. Reg. 909 under the PBA effective May 1, 2018 ("**Post-May 2018 Rules**"), is finalized and published.
- April 30, 2018: December 31, 2017 actuarial valuation report filed for Plan.
- May 1, 2018: Post-May 2018 Rules generally become effective, including new requirement to have transfer ratio of at least 105% in order to be eligible for a contribution holiday
- August 2018: FSCO publishes a chart illustrating their position on the provisions governing contribution holiday rules applicable in five scenarios, based on various valuation and filing dates.
- February 2019: FSCO publishes additional Q&As on various interpretative issues.
- May 21, 2019: O. Reg 105/19 (which amends the Regulations) is published, to address many of the interpretative issues which were created by the Post-May 2018 Rules.
- July 17, 2019: Letter received from FSRA to HONI's counsel regarding the interpretation of the Ontario funding rules in respect of the impact of the Asset Transfer.

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Section 4. ANALYSIS

Below is the analysis on each of the pension issues that I have been asked to address, as they pertain to the period 2018-2022.

ITEM 1: ***The effects on HONI's contribution holiday permissibility, following FSRA's determination of a March 1, 2018 effective date for the transfer of pension assets and liabilities in relation to the in-sourcing of call centre functions from Inergi LP and Vertex Customer Management (Canada) Ltd. to Hydro One.***

The March 1, 2018 Asset Transfer required the filing of an asset transfer valuation report as at that date, the effect of which will result in the Post-May 2018 Rules becoming applicable effective March 1, 2018. This result is affirmed by the letter dated July 17, 2019 from FSRA to HONI's counsel regarding the interpretation of the Ontario funding rules in respect of the impact of the asset transfer.

Applying the Post-May 2018 Rules has a significant impact on a plan sponsor's ability to take a contribution holiday.

- Under the rules in effect prior to the Post-May 2018 Rules ("**Pre-May 2018 Rules**"), a plan was required to have both a going concern and solvency surplus, and such surplus could then be applied towards a contribution holiday.
- Under the Post-May 2018 Rules, in addition to being fully funded on a going concern basis (including a Provision for Adverse Deviations) and on a solvency basis, a plan must also have a transfer ratio of at least 105% in order to be eligible for a contribution holiday.

Because of the requirement to follow the Post-May 2018 Rules starting from March 1, 2018, HONI would not be permitted to take a contribution holiday effective March 1, 2018, as the Hydro One Pension Plan (**"Plan"**) does not have a transfer ratio in excess of 105%. The Plan's transfer ratio as at March 1, 2018 was 72%.

Further, if a contribution holiday were to have been taken in the interim (while awaiting the approval of the asset transfer) on the basis of the Pre-May 2018 Rules, retroactive funding back to March 1, 2018 would subsequently be required to reverse the contribution holiday.

Under Section 80 of the PBA, FSCO/FSRA shall consent to an asset transfer if all of the specified regulatory requirements therein are satisfied. As part of preparing this Report, we reviewed the asset transfer valuation report, and in my opinion the requirements have been met. As a result, the asset transfer valuation report and the asset transfer are expected to be approved by FSRA.

ITEM 2: ***The likelihood of HONI being able to take a contribution holiday during the 2018-2022 period as a result of the transfer ratio of the Plan increasing to more than 105%.***

The likelihood of HONI being able to take a contribution holiday at any time during this period is extremely remote. Based on our analysis, there is a 0.0% probability of the Plan's transfer ratio being above 105% at January 1, 2019 and January 1, 2020. There is a 0.3% probability of the Plan's transfer ratio being above 105% at January 1, 2021 and a 1.2% chance of the Plan's transfer ratio being above 105% at January 1, 2022.

Please refer to Section 5 for further details and analysis on this item.

ITEM 3: ***The general effect of the Post-May 2018 Rules on contribution holidays and contribution stability practices. In addition, whether the permissibility of a contribution holiday should necessarily result in a plan sponsor utilizing this contribution holiday, as it relates to risk management and general governance principles, and whether this has changed following the enactment of the Post-May 2018 Rules.***

A key purpose of the Post-May 2018 Rules, as we understand it, was to create a more sustainable funding regime, in part where contribution requirements are more predictable and stable, and to lessen the contribution volatility that was inherent in the prior regime. The going concern funding rules have been strengthened, which are intended to be long term and more predictable by their nature. The solvency funding rules, which are subject to significant volatility, are now only applicable to plans with sizeable solvency deficits.

As noted earlier, under the Post-May 2018 Rules, a plan must be fully funded (including a Provision for Adverse Deviations) on a going concern basis and solvency basis, and must also have a transfer ratio of at least 105% in order to be eligible for a contribution holiday.

For a plan such as HONI's where, for purposes of determining the solvency liabilities of the plan, the value of benefits arising from future inflation are to be excluded, there can be a significant difference between solvency liabilities and windup liabilities. As the transfer ratio calculation makes reference to windup liabilities (rather than solvency liabilities), the introduction of a transfer ratio test for contribution holiday purposes is a significant change from the previous rules for plans such as these.

The Plan had a solvency surplus at December 31, 2017 (111% solvency funded ratio), but was only 73% funded on a transfer ratio basis (the difference owing entirely to the exclusion of the above-referenced future inflation liabilities).

While HONI would have been eligible for a contribution holiday under the Pre-May 2018 Rules due to the Plan's solvency surplus position (coupled with its going concern surplus), it is not eligible for a contribution holiday under the Post-May 2018 Rules for the foreseeable future (as further discussed in Section 5) due to the more onerous transfer ratio test.

The effect of the Post-May 2018 Rules is to significantly reduce the scenarios under which a contribution holiday will be permitted. In effect, a much higher threshold for the funded level of a plan is now required. The Post-May 2018 Rules will become effective for the Plan on March 1, 2018 as a result of the aforementioned asset transfer, as further confirmed by the FSRA letter dated July 17, 2019.

Unless a plan already has a transfer ratio in excess of 105%, there would be no expectation of a contribution holiday in the future. The Post-May 2018 Rules are not structured so as to target funding to a 105% transfer ratio level, because special payments to fund a solvency deficiency only arise when the solvency ratio is below 85%; therefore, absent very favourable economic or demographic experience, a plan with a transfer ratio well below 105% would expect to continue making normal cost contributions for the foreseeable future and not be eligible for a contribution holiday.

Further, eligibility for a contribution holiday does not equate to a plan sponsor taking a contribution holiday. In my opinion, the ability to take a contribution holiday does not (and should not) necessitate actually making use of this ability. Unless required due to Income Tax Act Regulations, the decision to make use of a contribution holiday must be considered in the context of the plan sponsor's long-term objectives for the plan, the plan's investment, benefit and funding policies (should they exist), and any short term financial considerations. Under the Pre-May 2018 Rules, the threshold for contribution holiday eligibility was such that, in our experience, some plan sponsors chose to overfund a plan and not take a contribution holiday, as a part of the above policies and their risk management practices. Under the Post-May 2018 Rules, the threshold for contribution holiday eligibility is much higher, and we therefore expect that different considerations will be required when deciding whether to make use of a contribution holiday, if one becomes available.

ITEM 4: ***The permissibility and general practices around filing (or not filing) a cost certificate for a contribution holiday in a year where a full valuation report is also to be filed.***

In accordance with the Pre-May 2018 Rules, for a plan fiscal year ending after June 29, 2017 and before January 1, 2020, a contribution holiday is only permitted if an actuarial cost certificate is filed within the first 90 days of the fiscal year. A similar requirement also existed for a plan fiscal year ending after June 29, 2010 and before January 1, 2013. No such requirement existed between these two periods.

The cost certificate requirement was introduced following the 2008 financial crisis; it is my understanding that the rationale behind this requirement was to ensure that a contribution holiday was not continued in an inter-valuation year (e.g., in the fiscal years between triennial valuations), when it could no longer be supported by a more current financial position of the pension plan.

Filing a cost certificate has been viewed by plan sponsors as administrative in nature, particularly in years when a full actuarial valuation report is scheduled to be filed with FSCO/FSRA.

In fiscal years where a full actuarial valuation report is scheduled to be filed, the full valuation report takes precedence (FSCO has in fact issued Q&As to this effect). Some plan sponsors have submitted a separate cost certificate within the first 90 days regardless, despite knowing the full valuation report would later render it irrelevant. However, where the full valuation report was expected to be filed within a reasonable time period after the 90 days, some plan sponsors have skipped the cost certificate filing and only filed the full valuation report. In our experience, this latter approach has not been rejected by FSCO.

In our experience, FSCO has been flexible with deadlines and the requirements of a cost certificate. FSCO reserved the right to reject a cost certificate if it was filed beyond the 90 days, but has frequently accepted the filing of a cost certificate beyond the 90 days, particularly in situations where it was clear that a contribution holiday could continue to be supported (e.g., plans with large surpluses). In particular, following the reinstatement of the cost certificate filing requirement for 2017, after its absence for several years, the filing of a cost certificate was an oversight by some plans. In our experience, FSCO did not enforce the deadline and simply encouraged retroactive filing, or a full valuation filing in lieu.

Generally, under the Pre-May 2018 Rules, it was not uncommon for a plan sponsor to forego a cost certificate filing and file only a full valuation report in a valuation year, so long as they expected that the full valuation filing would continue to support a contribution holiday, and the full valuation was expected to be filed reasonably soon after the 90 day cost certificate deadline.

HONI's approach in 2018 of foregoing a cost certificate, and filing only a full valuation report on April 30, has been done by other plan sponsors, and we are not aware of FSCO rejecting the approach in the past.

ITEM 5: ***The impact of the Post-May 2018 Rules, as it relates to:***

- ***Observed changes in FSCO or FSRA practices towards contribution holidays and associated actuarial filings.***
- ***The level of uncertainty for pension plan stakeholders and service providers around the interpretation and practical effect of the Post-May 2018 Rules following their announcement, particularly during the period before FSCO/FSRA published Q&As/guidelines in August 2018 and additional clarifying amendments were made to O. Reg 909 on May 21, 2019.***
- ***The reasonableness of HONI's response to this uncertainty, as it pertains to actuarial filings and contribution holidays.***

Following the publication of the Post-May 2018 rules, stakeholders and service providers were operating in an environment of significant uncertainty around how certain provisions would apply in practice, and how they would apply to particular situations. Many interpretative issues existed.

The process of Ontario pension reform spanned several years. After various consultations on reform concepts, a description of proposed funding changes was released for comment in December 2017. This release did not contain the detailed regulations, which are typically required in order to understand the details of application in practice. These detailed regulations themselves were not finalized and published until April 20th, 2018, leaving only ten days for interpretation and action before they became effective on May 1, 2018.

Following the publication of the regulations, definitive answers on questions of interpretation and practical application were challenging to obtain from either FSCO or the Ministry of Finance. Generally, information from FSCO contacts could only be obtained through verbal discussions. The first definitive form of additional information came in the form of the August 2018 FSCO publication illustrating their position on the provisions governing contribution holiday rules applicable in five scenarios, based on various valuation and filing dates. For plans with possible contribution holidays in calendar 2018 or with valuation filings due (or already submitted) in 2018, the period between the publication of the Post-May 2018 Rules and August 2018 lacked clarity. Following the August 2018 publication, significant uncertainty and open interpretative issues remained. The subsequent material round of publication did not occur until February 2019, in the form of additional Q&As from FSCO.

O. Reg 105/19 (which amends the Regulations), published on May 21, 2019, is largely a clarifying amendment, required in order to address many of the interpretative issues which were created by the Post-May 2018 Rules. In other words, an additional set of regulations was required to address issues that arose from the previous set of regulations. O. Reg 105/19 particularly deals with uses of surplus (which is directly relevant to contribution holidays).

In the absence of official guidance, policy or Q&As from FSCO or the Ministry of Finance, stakeholders and service providers have often had to make their own reasonable interpretations during the period since the publication of the Post-May 2018 Rules. It has been our experience that FSCO was generally flexible on issues of interpretation during this period of uncertainty, as has been FSRA since they officially assumed the responsibility for the regulation of FSCO on June 8, 2019, so long as the approach was reasonable.

HONI's approach of not filing a cost certificate in early 2018, and instead relying on the planned filing of a full valuation in April 2018 (prior to the enactment of the Post-May 2018 Rules), to support a potential contribution holiday, would have been consistent with past practice. In my opinion, this was a reasonable interpretative approach during the period of uncertainty following the announcement of the proposed funding changes.

Section 5. TRANSFER RATIO ANALYSIS

ANALYSIS OF PROJECTED TRANSFER RATIO

The analysis contained in this Section 5 addresses the requested issue of "*The likelihood of HONI being able to take a contribution holiday during the 2018-2022 period as a result of the transfer ratio of the Plan increasing to more than 105%.*"

For this purpose, we have prepared a stochastic analysis of the projected transfer ratio at January 1, 2020, January 1, 2021 and January 1, 2022. The stochastic analysis is informed by the scenarios generated as part of Eckler's economic model. Eckler uses the GEMS® economic model, a state-of-the-art tool produced by Conning, a third-party financial software developer based in the U.S. The software was originally developed for large insurers to help manage and model asset/liability risks. The economic scenarios used include 1000 paths for projected asset class returns and real yields, which in turn, impact the projected market vaues of assets and level of wind-up liabilities. Further details on the economic model are presented in Appendix C.

In order to project the future market value of assets, we have relied on the value of assets presented in the January 1, 2019 actuarial cost certificate prepared by Willis Towers Watson, and made the following assumptions:

- Contributions made to the Plan will only reflect normal cost contributions, inclusive of the required PfAD determined assuming that the Plan remains open;
- Benefit payments from the Plan increase annually from the level implied based on the pensioner data summaries in the January 1, 2019 actuarial cost certificate, by 100% of the simulated increase in the Consumer Price Index, based on Eckler's economic model;
- The target asset mix will remain the same over the period until January 1, 2022, and will be rebalanced annually; and
- Asset class returns are as simulated based on Eckler's economic model.

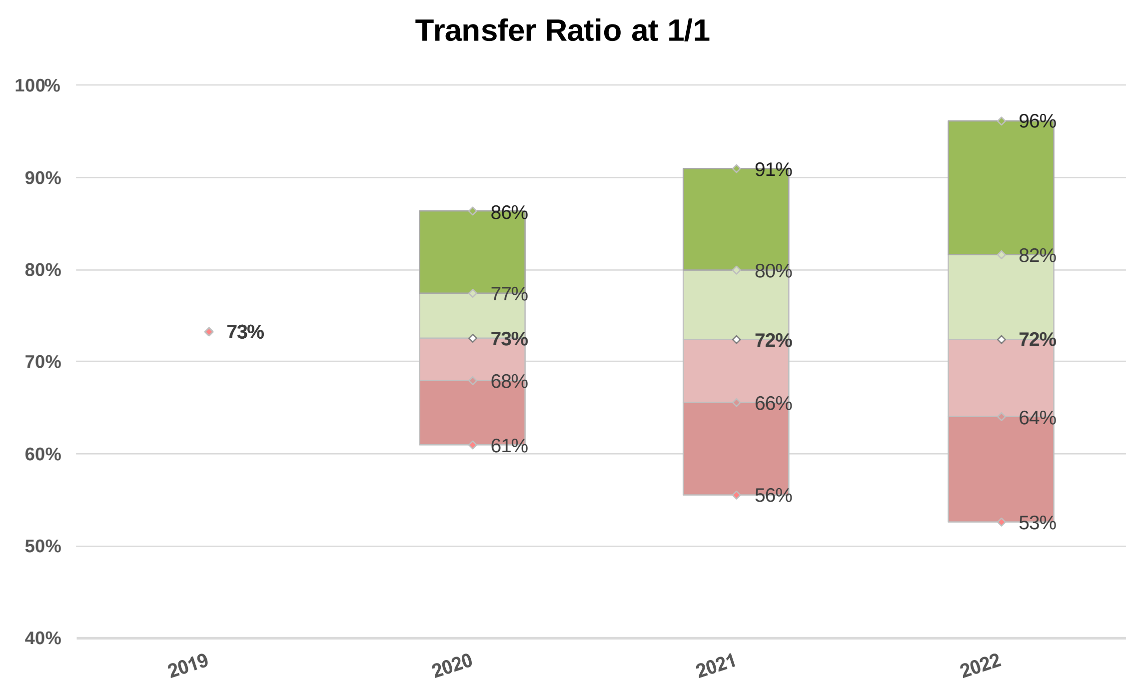
In order to project the future value of the wind-up liabilities, we have relied on the value of the liabilities, incremental cost, and liability duration as presented in the January 1, 2019 actuarial cost certificate and the December 31, 2017 actuarial valuation report, both prepared by Willis Towers Watson. The liability projections reflect simulated levels of real yields based on Eckler's economic model.

Based on the data and assumptions described above, the follow table summarizes the estimated probability of the transfer ratio exceeding 105% at January 1, 2020, January 1, 2021 and January 1, 2022.

Valuation Date	January 1, 2020	January 1, 2021	January 1, 2022
Estimated probability that transfer ratio exceeds 105%	0.0%	0.3%	1.2%

ECKLER

The following chart shows the distribution of the projected estimated transfer ratio, at January 1, 2020, January 1, 2021 and January 1, 2022. For reference, the transfer ratio at January 1, 2019, as disclosed in the actuarial cost certificate, is also shown. The breakpoints noted for the distribution represent, from the top to bottom of each bar, the 95th, 75th, 50th, 25th and 5th percentile.[1]



Thus, the median projected transfer ratios at January 1, 2020, Janaury 1, 2021 and January 1, 2022 are 73%, 72%, and 72% repectively. At January 1, 2022, there is only a 1.2% chance that the transfer ratio is above 105%. In other words, over the 1000 simulations considered, there were 12 scenarios in which the transfer ratio was greater than 105% at January 1, 2022. In those scenarios, annualized returns over the 3-year period ending December 31, 2021 averaged 17% p.a. and real yields averaged 2.1% at January 1, 2022 (for comparison, the real yield was 0.8% as at January 1, 2019)

RELIANCE

To prepare the calculations presented in this Section 5, we have relied on the December 31, 2017 actuarial report and January 1, 2019 actuarial cost certificate as prepared by HONI's actuary, Willis Towers Watson.

[1] For example, the 5th percentile means that 5% of projected outcomes fall below that threshold, and 95% fall above. The 50th percentile, which is also referred to as the "median", is the point at which half of projected outcomes fall below the threshold, and 50% fall above.

ECKLER

Section 6. ACTUARIAL OPINION

This report has been prepared and my opinion given in accordance with accepted actuarial practice in Canada. Specifically, it is my opinion that:

a) the data on which the valuation is based are sufficient and reliable for the purposes of the valuation;

b) the assumptions are appropriate for the purposes of the valuation; and

c) the methods employed in this valuation are appropriate for the purposes of the valuation.

Respectfully submitted,

Simon J. Nelson, FSA, FCIA

August 1, 2019

Appendix A. CURRICULUM VITAE

<u>Education</u>: Bachelor of Science (Hons.), Mathematical Statistics, University of Toronto, 1998
Fellow, Society of Actuaries, 2006
Fellow, Canadian Institute of Actuaries, 2006

<u>Employment</u>: Consulting Actuary, Eckler Ltd., Toronto, 2013-present;
Principal, Eckler Ltd, Toronto, 2017-present
Consultant, Towers Watson (now Willis Towers Watson), Toronto, 1997-2013

Co-Leader – Toronto-Halifax-Winnipeg-Vancouver Pension Actuarial Practice, Eckler Ltd., 2017-present;

<u>Professional Activities</u>:

Canadian Institute of Actuaries (CIA)

- Member, Pension Advisory Committee (2018 – present)
- Pension Plan Financial Reporting Committee
  - ASB Liaison (2019-present)
  - Chair (2015-2017)
  - Vice-Chair (2013-2015)
  - Member (2012-2013)
- Member, Designated Group, Mortality improvement scale for commuted value purposes (2018-2019)
- Member, Task Force, Modelling (2015-2017)

Actuarial Standards Board (ASB)

- Member, Actuarial Standards Board (2019 – present)

Association of Canadian Pension Management

- Member, National Policy Committee (2019 – present)

Other

- FSRA Pension Stakeholders Industry Advisory Group (2018-2019)

Appendix B. INFORMATION EXAMINED

To prepare this report, we examined or were provided access to the following documents:

- The publicly available documents posted on the OEB website pertaining to EB-2019-0122
- The funding policy for the Hydro One Pension Plan (Reg# 1059104)
- The Statement of Investment Policies & Procedures for the Plan
- The December 31, 2017 actuarial report, January 1, 2019 actuarial cost certificate and March 31, 2018 asset transfer report for the Plan
- A letter dated July 17, 2019 from FSRA to HONI’s pensions counsel regarding the interpretation of the Ontario funding rules under the Pension Benefits Act and Regulation 909 in respect of the impact of the Hydro One Pension Plan Asset Transfer Actuarial Valuation as at March 1, 2018 (“**Asset Transfer Report**”) on the funding of the Plan

Appendix C. ASSUMPTIONS AND METHODS

Eckler Capital Market Assumptions

Asset Class Returns and Standard Deviations

	Asset Class	Geometric Return 10 Yr	Geometric Return 20 Yr	Geometric Return 30 Yr	Standard Deviation 10 Yr	Standard Deviation 20 Yr	Standard Deviation 30 Yr
	Inflation	1.9%	2.0%	2.0%	1.0%	1.0%	1.0%
Fixed Income	Cash/Short Term	2.1%	2.3%	2.5%	1.0%	1.4%	1.7%
Fixed Income	Universe Bonds	2.8%	3.3%	3.7%	3.0%	3.5%	3.8%
Fixed Income	Short Bonds	2.9%	3.2%	3.5%	1.5%	1.9%	2.2%
Fixed Income	Long Bonds	2.7%	3.3%	3.8%	5.5%	6.1%	6.5%
Fixed Income	Corporate Bonds	3.6%	3.9%	4.2%	2.9%	3.3%	3.6%
Fixed Income	Real Return Bonds	1.7%	2.5%	3.1%	10.3%	10.9%	10.7%
Fixed Income	High Yield Bonds	5.6%	6.1%	6.4%	11.4%	11.4%	11.4%
Fixed Income	Mortgages	3.4%	3.7%	4.0%	3.3%	3.5%	3.6%
Fixed Income	Core Plus Bonds	3.6%	4.0%	4.3%	3.0%	3.3%	3.5%
Fixed Income	EM Debt	6.1%	6.5%	6.7%	9.6%	9.8%	9.9%
Fixed Income	Private Debt	5.3%	5.6%	5.9%	4.5%	4.6%	4.7%
Equities	Canadian Equity	6.9%	7.2%	7.2%	18.4%	18.4%	18.5%
Equities	US Equity	7.0%	7.2%	7.2%	17.6%	17.8%	17.8%
Equities	International Equity	7.1%	7.2%	7.1%	18.7%	18.9%	18.9%
Equities	Global Equity	7.1%	7.3%	7.2%	17.7%	17.9%	17.9%
Equities	Small Cap Equity	7.8%	7.7%	7.6%	19.6%	19.9%	19.9%
Equities	EM Equity	8.1%	8.0%	8.0%	22.3%	22.5%	22.5%
Alternatives	Real Estate	5.6%	5.6%	5.6%	8.1%	8.2%	8.3%
Alternatives	Infrastructure	6.7%	6.6%	6.5%	11.2%	11.2%	11.3%
Alternatives	Private Equity	9.0%	9.3%	9.4%	20.8%	20.9%	21.0%
Alternatives	Hedge Funds	6.0%	6.4%	6.6%	10.6%	10.7%	10.8%

Real Yields

	January 1, 2020	January 1, 2021	January 1, 2022
Median Real Yield	0.9%	1.0%	1.0%

Appendix D. EXPERT WITNESS MANDATE

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Direct Line: (403) 260-3607
Email: mfeser@mccarthy.ca

VIA EMAIL

July 19, 2019

Ian Edelist, Simon Nelson
Eckler Ltd.
iedelist@eckler.ca; snelson@eckler.ca

Dear Sirs,

Re: Expert Witness Mandate for Hydro One Networks Inc.

Thank you for agreeing to provide an independent expert witness report (the "**Report**") that may be used as evidence in proceedings before the Ontario Energy Board ("**OEB**") or in subsequent appeal proceedings by our client Hydro One Networks Inc. ("**HONI**"). You have confirmed your understanding that the authors of the Report may be required to appear before the OEB and address questions regarding the content of the Report through cross-examination.

Issues to be addressed in the Report

In the Report, we request that you provide your expert opinion on the following pension issues as they pertain to the period 2018-2022:

- The effects on HONI's contribution holiday permissibility, following FSRA's determination of a March 1, 2018 effective date for the transfer of pension assets and liabilities in relation to the in-sourcing of call centre functions from Inergi LP and Vertex Customer Management (Canada) Ltd. to Hydro One.

- The likelihood of HONI being able to take a contribution holiday during the 2018-2022 period as a result of the transfer ratio of the Plan increasing to more than 105%.

- The general effect of the Post-May 1, 2018 Rules on contribution holidays and contribution stability practices. In addition, whether the permissibility of a contribution holiday should necessarily result in a plan sponsor utilizing this contribution holiday, as it relates to risk management and general governance principles, and whether this has changed following the enactment of the Post-May 1, 2018 Rules.

- The permissibility and general practices around filing (or not filing) a cost certificate for a contribution holiday in a year where a full valuation report is also to be filed.

- The impact of the amendments to O. Reg. 909 under the Pension Benefits Act effective May 1, 2018 ("**Post-May 1, 2018 Rules**"), as it relates to:
    - Observed changes in FSCO/FSRA practices towards contribution holidays and associated actuarial filings.
    - The level of uncertainty for pension plan stakeholders and service providers around the interpretation and practical effect of the Post-May 2018 Rules following their announcement, particularly during the period before FSCO/FSRA published Q&As/guidelines in August 2018 and additional clarifying amendments were made to O. Reg 909 on May 21, 2019.
    - The reasonableness of HONI's response to this uncertainty, as it pertains to actuarial filings and contribution holidays.

For the purpose of preparing our Report, you confirm that you will have examined or have been provided access to the following documents:

- The publicly available documents posted on the OEB website pertaining to EB-2019-0122
- The funding policy for the Hydro One Pension Plan (Reg# 1059104) (the "**Plan**")
- The SIP&P for the Plan
- The December 31, 2017 actuarial report and January 1, 2019 actuarial cost certificate for the Plan
- A letter dated July 17, 2019 from FSRA to Hydro One's pensions counsel regarding the interpretation of the Ontario funding rules under the Pension Benefits Act and Regulation 909 in respect of the impact of the Hydro One Pension Plan Asset Transfer Actuarial Valuation as at March 1, 2018 (Hydro One Asset Transfer Report) on the funding of the Plan

Due Date of Report

You confirm that your report is expected to be complete by August 1, 2019.

Expert's Duty

You acknowledge and agree that your duty as an expert is as follows:

a) To provide opinion evidence that is fair, objective and non-partisan;

b) To provide opinion evidence that is related only to matters that are within your area of expertise;

c) To provide such additional assistance as the OEB may reasonably require, to determine a matter in issue; and

d) That the duties referred to above prevail over any obligation which you may owe to any party including the party by whom you are engaged.

The OEB requires that you include with the Report a number of specific criteria, including an "acknowledgement of expert's duty" form in the form set out by the Ontario Energy Board[1] which includes the duties set out in items a) to d) above. Please see Schedule "A" hereto for the items which the OEB requires the Report to include.

Please acknowledge that the terms contained herein are acceptable by return of copy.

Yours truly,

Gordon M. Nettleton

AGREED TO AND ACCEPTED as of this 19 day of July, 2019.

____

[1] See https://www.oeb.ca/oeb/_Documents/Regulatory/Rules_Form-A_Experts_Duty.pdf

Schedule "A" – Ontario Energy Board *Rules of Practice and Procedure*[2] Rule 13A.03:

13A.03 An expert's evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence; and

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence.

(f) an acknowledgement of the expert's duty to the Board in Form A to these Rules, signed by the expert.

[2] See https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/OEB-Rules-of-Practice-and-Procedure-20161028.pdf

Appendix E. ACKNOWLEDGEMENT OF EXPERT’S DUTY

This Appendix E contains our “acknowledgement of expert’s duty” in the form set out by the OEB.

Proceeding: EB-2019-0122

1. My name is Simon Nelson. I live at Toronto, in the Province of Ontario.

2. I have been engaged by or on behalf of McCarthy Tetrault to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
    a. to provide opinion evidence that is fair, objective and non-partisan;
    b. to provide opinion evidence that is related only to matters that are within my area of expertise; and
    c. to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

August 1, 2019

Simon J. Nelson

OEB INTERROGATORY #204

Reference:
F-05-01 p. 5-6

Interrogatory:
At the above reference, Hydro One describes the uncertainty around its ability to take a pension contribution holiday in 2020, and that it almost certain that it will not be able to take a contribution holiday in 2021 and 2022 due to the new funding rules. Hydro One further proposes that given the uncertainty, it will track the difference between pension costs recovered in rates and actual pension payments made to the plan.

a) Is Hydro One proposing to track the difference in its existing Pension Differential variance account?

b) If so, the current Pension Differential account only tracks the difference related to the OM&A component pension costs. Given that pension costs have both a capital and OM&A component, how is Hydro One proposing to track the difference impacting the capitalized component?

c) If Hydro One is in fact proposing a new account for this purpose, then please indicate this intention and file a draft accounting order.

Response:
a) Hydro One does not intend to take a pension contribution holiday during the rate period for the reasons outlined in the response in Exhibit I, Tab 01, Schedule OEB-203 part a). As such, Hydro One will use the existing Pension Cost Differential account to track the difference between pension costs recovered in rates and pension payments made to the Plan.

b) The existing Pension Cost Differential account will capture the variances related to the OM&A component of pension costs. As it stands, the capital component of pension costs will be captured in the Capital In-Service Variance Account (CISVA). Additionally, at the next rebasing application, Hydro One will rebase at a lower amount reflecting the actual pension contributions that were capitalized. Please refer to Exhibit I, Tab 01, Schedule OEB-203 part f) for full discussion.

Witness: Samir Chhelavda

c) As stated in part a) above, Hydro One does not intend to take a contribution holiday. Moreover, it is unlikely that there will be a material revenue requirement impact arising from any differences between the actual pension costs (capital component) contributed to the Pension Fund and the estimated pension costs (capital component) approved by the OEB.

In summary revenue requirement impact will not be material and that any differences will be captured in the CISVA.

OEB INTERROGATORY #205

Reference:
F-05-01 p.9

Interrogatory:
At the above reference, Hydro One indicates that it is seeking to recover its OPEB costs on an accrual basis and presents a table that breaks-out between capital and OM&A, the amount that is being sought in respect to OPEB costs for 2020.

a) Please provide the OPEB valuation that support the amount for 2020.

b) Please provide the amounts in respect to OPEB costs that are being capitalized in this application for 2021 and 2022.

c) What is the basis for the amounts being capitalized in each of these years?

d) In Table 3, Hydro One provides a historical summary of OPEB costs it has recovered in rates (on an accrual basis) compared to the related cash payments for the same period. The analysis indicates that Hydro One has historically over-collected with respect to its OPEB costs. Please explain how these over-collections have been used.

Response:
a) Please see Attachment 1 to this exhibit.

b) 2021 OPEB costs being capitalized in this Application: $20 million.
2022 OPEB costs being capitalized in this Application: $20 million.
Please refer to Exhibit I, Tab 01, Schedule OEB-221 for further details on OPEB costs.

c) Capitalization of OPEB costs is based on the forecasted labour cost attributable to capital based on the forecasted work program for that year.

d) Recoveries in excess of cash benefit payments form part of Hydro One's working capital, which is invested in capital and OM&A work programs.

It should be noted that in Table 3 of Exhibit F, Tab 05, Schedule 01, there is a footnote indicating that the capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net Excess as noted does not represent the excess recovery in each year.

Willis Towers Watson

December 13, 2017

Our Ref: 601835/3140218

Ms. Cathy Sewell
Senior Finance Advisor, Corporate Finance
Hydro One Inc.
483 Bay Street, South Tower
Toronto, Ontario M5G 2P5

Dear Cathy:

HYDRO ONE INC. ("HYDRO ONE") PROJECTED 2018 – 2023 BENEFIT COST UNDER FASB ASC 715-20-50

As requested, we have prepared the projected benefit cost for 2018 to 2023 under FASB Accounting Standards Codification Topic 715-20-50 ("US GAAP") for the following pension and benefits plans sponsored by Hydro One:

- Hydro One Pension Plan (the "RPP");
- Hydro One Defined Contribution Plan (the "DCPP");
- Hydro One Supplemental Pension Plan (the "SPS/DSPS");
- Hydro One Non-Pension Post Retirement Benefits (the "Hydro One PRB" and the "Inergi PRB"); and
- Hydro One Post-Employment Benefits (the "PEB").

It is intended that this letter is read in conjunction with our Actuarial Valuation Report Disclosure for Fiscal Year Ending December 31, 2016 (the "2016 Year-end Reports") for:

- Hydro One Pension Plan (dated January 2017); and

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Towers Watson Canada Inc.

■ Hydro One Non-Pension Post-Retirement Benefits Plan, Post-Employment Benefits Plan and Supplemental Pension Plan (dated January 2017).

Key Results - Projected Benefit Cost ($millions)

Based on the assumptions and approaches set out later in this letter, the projected benefit cost for the various arrangements are as follows (actual 2017 amounts have been included for reference purposes):

	2017	2018	2019	2020	2021	2022	2023
RPP	$87.8	$47.6	$37.9	$26.3	$12.9	$(1.6)	$(14.8)
SPS/DSPS	$8.4	$7.9	$7.7	$7.5	$7.3	$7.1	$6.9
DCPP	$1.2	$1.5	$1.8	$2.2	$2.6	$3.0	$3.4
Hydro One PRB	$104.0	$86.0	$88.4	$90.8	$93.9	$97.6	$102.2
Inergi PRB	$1.5	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2
PEB	$10.1	$8.9	$9.1	$9.3	$9.4	$9.6	$9.8
Total	**$213.0**	**$153.1**	**$146.1**	**$137.3**	**$127.3**	**$116.9**	**$108.7**

The 2017 projected benefit cost for the PEB will be finalized in early 2018, following the completion of the November 30, 2017 PEB valuation.

The projected benefit cost in aggregate during the projection period is higher when compared to the estimates provided last year. This change is primarily due to the net impact of the following:

- Decrease to the discount rate (from 3.70% used last year for projection purposes, compared to 3.40% this year for all plans);
- Significant assumed increase to active membership during the projection period; offset by
- Decrease in the per capita claim cost and trend assumptions as part of the January 1, 2017 valuation (applicable to the Hydro One and Inergi PRB plans); and a
- Decrease to the salary scale assumption for all members.

Detailed schedules providing the development of the benefit cost by year for each plan, other than for the DCPP, can be found in the enclosed Appendices. As requested, we have also included the allocation of projected benefit costs to the active and inactive members of the plans and an allocation of the projected benefit costs in respect of the Inergi and Non-Inergi obligations of the plans. Appendices A, B and C provide projection details as follows:

■ Appendix A – Projections for RPP and SPS/DSPS;

■ Appendix B – Projections for Hydro One PRB and Inergi PRB; and

■ Appendix C – Projections for PEB.

Membership Data

Summaries of data upon which these projections were based can be found in the following documents:

RPP:	Hydro One Pension Plan actuarial valuation report as at December 31, 2016 dated May 31, 2017 (the "Funding Report");
SPS/DSPS:	Hydro One Supplementary Pension Plan December 31, 2016 actuarial report dated September 2017 (the "LOC Report");
Hydro One PRB and Inergi PRB:	Presentation to Hydro One dated November 2017 with respect to valuation results as at January 1, 2017 (the "PRB Presentation"); and
PEB	Presentation to Hydro One dated January 2017 with respect to valuation results as at November 30, 2016 (the "PEB Presentation").

In addition, information regarding new entrant assumptions can be found under the Methodology section of this letter.

Assumptions

As instructed by Hydro One, we have reflected the following assumption changes (when compared to the assumptions used in the 2016 Year-end Reports):

- The discount rate used in our calculations is based on long-term high-quality corporate bond yields at November 30, 2017. Please refer to our memo dated January 4, 2017 for more details regarding the methodology used to determine the discount rate. The discount rate as at December 31, 2017 and over the projection period will remain the same as the discount rate applicable as at November 30, 2017.

- The Merit and Promotion (M&P) scale has been updated to reflect the assumptions used for the December 31, 2016 going concern funding valuation as outlined in the Funding Report.

- Expected wage increase of the new M&P scale plus:

  - 2.5% for Management employees ("MCP");
  - 1.0% for 2018, 2.0% for 2019 to 2023 and 2.5% thereafter for members of the Power Workers' Union ("PWU"); and
  - 0.5% for 2018 and 2019, 2.0% for 2020 to 2023 and 2.5% thereafter for members of the Society and Professionals ("Society")

All other assumptions are summarized in Appendix D.

Plan Provisions

Summaries of the provisions for the different plans other than the DCPP, can be found in the Funding Report, LOC Report, PRB Presentation and the PEB Presentation.

DCPP

For Management employees hired on or after July 1, 2015, benefits are accrued on a Defined Contribution (DC) basis. Members may elect to contribute 4%, 5% or 6% of pensionable earnings. Hydro One matches 100% of member contributions. The estimated annual pension expense for the DCPP is equal to the estimated annual contributions to the plan based on the profile of existing and new management employees (see Methodology section below) and assuming all members contribute 6% of pensionable earnings.

It was assumed that members of the DCPP will continue to be eligible for the Hydro One PRB Plan, with the provisions in place as of the date of this letter.

Methodology

Assets

The market value of assets as at December 31, 2017 for the RPP was estimated based on the actual market value of assets as at October 31, 2017, projected to December 31, 2017 using estimated cash flows and assuming a 6.5% per annum investment return net of all expenses for November 1, 2017 to December 31, 2017. The estimated market value of assets over the remainder of the projection period has been extrapolated from the estimated market value of assets as at December 31, 2017. The extrapolations are based on estimated contributions and benefit payments in the intervening period and a return on assets assumption of 6.5% per annum.

Hydro One contributions to be made to the RPP over the projection period are assumed to be made in accordance with the estimated minimum contribution requirements outlined in the Funding Report, adjusted for expected future new entrants to the RPP. It has been assumed that no special funding payments are required during the projection period. Actual contributions to be made following the next filed actuarial valuation may be significantly different due to a number of factors, including experience gains and losses and future changes to liability measurement assumptions. In addition, it is expected that minimum contribution requirements will change as a result of upcoming changes to the Ontario pension funding requirements. The impact of these upcoming changes is not known at this time.

As instructed by Hydro One, the estimated member contributions to be made to the RPP are in accordance with the rates outlined in the Funding Report. We have not reflected future increases in employee contributions beyond those described that may come into effect in future years.

Consistent with Hydro One's actual disclosures at December 31, 2016, we have included the value of Refundable Tax Account balance for the SPS/DSPS in our calculations. In addition, we have included the expected letter of credit fee in the expense calculations over the projection period.

Hydro One PRB, Inergi PRB and the PEB are not funded and have no assets.

Benefit Obligations and Service Cost

The projected benefit obligations and service cost over the period (December 31, 2017 to December 31, 2023) for the RPP have been estimated based on the most recent membership data as set out in the Funding Report projected to each December 31 using the assumptions set out in this letter. For PRB and PEB, the projected benefit obligations and service cost have been estimated based on the most recent membership data as set out in the PRB and PEB presentations respectively. In addition, it was assumed that some active members terminating or retiring would be replaced by new entrants. As directed by Hydro One, we have assumed the following with respect to the new entrants:

For the RPP:

	Percentage of New Entrants in Category	Average Age	Average Earnings
Power Workers Union Members	65%	30	$80,000
Society Members	30%	33	$90,000
Management Members*	5%	40	$120,000

*Assumed to transfer from Society/PWU

As instructed by Hydro One, the RPP active membership in aggregate, is assumed to change at the following rates:

	2018	2019	2020	2021	2022	2023
Population Change %	10%	0%	(1%)	(1%)	(1%)	(1%)

For the DCPP:

In addition to the new entrants under the RPP, for each year commencing January 1, 2018, 35 new Management members are assumed to be hired externally. Each member is assumed to have average earnings of $120,000. No terminations or retirements were assumed under the DCPP over the projection period.

For the SPS/DSPS:

The projected benefit obligations and service cost over the projection period for the SPS/DSPS have been estimated based on the most recent membership data as set out in the LOC Report.

For the PRB plan:

	Percentage of New Entrants in Category	Average Age	Average Earnings
Power Workers Union Members	60%	30	$80,000
Society Members	27%	33	$90,000
Management Members	13%	40	$120,000

For the Hydro One PRB plan and the PEB, the active membership in aggregate, is assumed to change at the following rates:

	2018	2019	2020	2021	2022	2023
Population Change %	8%	0%	(1%)	(1%)	(1%)	0%

The active membership projection of the Hydro One PRB plan and the PEB reflects the open nature of the plans to all employee groups.

The projected benefit obligations and service cost over the projection period for the Inergi PRB have been estimated based on the most recent membership data as set out in the PRB Presentation. Given that this is a closed group, active membership will decline over time in accordance with the demographic assumptions.

Except as noted above, please refer to the 2016 Year-end Reports for additional details on methodology.

Allocation of Benefit Cost

Active and Inactive Split

As instructed by Hydro One, the projected benefit cost over the projection period is allocated to the active and inactive members of the plans as follows:

Current Service Cost	Allocated to active members
Interest Cost and EROA	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year
Amortization of net actuarial (gains)/losses	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year
Past service cost for RPP	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year
Past service cost for SPS/DSPS	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of that calendar year with the exception of certain past service costs for SPS/DSPS that are entirely in respect of former executives and are fully allocated to the inactive membership
Past service cost for the PRB plans	Entirely allocated to active members

Inergi and Non-Inergi Split

The projected benefit cost over the projection period is allocated to the Inergi and Non-Inergi portion of the plans as follows:

Current Service Cost	Allocated to Non-Inergi members
Interest Cost and EROA	Allocated to Inergi and Non-Inergi members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year
Amortization of net actuarial (gains)/losses	Allocated to Inergi and Non-Inergi members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year

Past service cost for SPS/DSPS	Entirely allocated to Non-Inergi members

Notes Concerning our Calculations

We have not reflected any factors over the projection period that would potentially result in the net benefit cost being different than expected including, but not limited to, changes to pension or benefit plan provisions other than those mentioned in this letter, actual investment experience in the pension fund after October 31, 2017, experience revealed in any new valuation of the plans, contributions to the pension fund significantly different than expected, any significant event such as material downsizing or acquisition/divestiture, change in accounting standards or additional changes to the assumptions or methodology.

Actuarial Certification

The calculations herein have been made in accordance with US GAAP with which we are familiar. The assumptions used were selected by Hydro One management for the purpose of preparing this letter, following discussions with Willis Towers Watson, and they are in accordance with accepted actuarial practice. The discount rate was selected by Hydro One based on long bond yields at November 30, 2017. In our opinion, the data on which the calculations are based are sufficient and reliable for the purpose of these estimates. This letter and attachments have been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

The results presented in this letter have been developed using a particular set of actuarial assumptions and methods. Other results could have been developed by selecting different actuarial assumptions and methods. The results presented in this letter are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events. The actual benefit cost levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions and the legislative rules, or as a result of future experience gains or losses, none of which has been anticipated at this time. Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future accounting valuations.

As at the date of this letter, we are not aware of any subsequent events that would have a material impact on the results of the projected benefit cost.

The information contained in this letter was prepared for Hydro One, for its internal budgeting purposes. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard.

The undersigned consultants with actuarial credentials meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinions contained herein. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Canada Inc.

Should you have any questions, please do not hesitate to contact us.

TOWERS WATSON CANADA INC.

In respect of the pension plans:

Suzanne Jacques

Suzanne Jacques, FCIA, FSA

David Kenny, FCIA, FSA

In respect of the post-retirement and post-employment plans:

Ross Cristiano, FCIA, FSA

Laura Ens, FCIA, FSA

Enclosures

cc: Samir Chhelavda, Arthur McGlashan — Hydro One Inc.
Davis Gonsalves, Tiffany Kuo, Kieran Gillet, Ulana Zadarko, Rasha Lawrence — Willis Towers Watson

Appendix D - Statement of Assumptions (RPP and SPS/DSPS)

The rates in the following table are on a per annum basis.

Measurement Date	**End of December 31 During Projection Period (2017-2023)**	**December 31, 2016 (as per year-end disclosures)**
Economic Assumptions		
Discount Rates:		
• RPP	3.40%	3.90%
• SPS/DSPS	3.40%	3.90%
Expected Long-term Return on Plan Assets (EROA) – RPP only [1]	6.50%	Same
Consumer Price Index (Inflation)	2.00%	Same
YMPE Increases	3.00%	Same
Increase in maximum pension under the Income Tax Act	3.00%	Same
Salary increases		2.50% + M&P (see Table 2)
Management	2.50% + M&P (see Table 1)	
Society	2018-2019: 0.50% + M&P; 2020-2023: 2.00% + M&P; 2024 onwards: 2.50% + M&P (see Table 1)	
PWU	2018: 1.00% + M&P; 2019-2023: 2.00% + M&P 2024 onwards: 2.50% + M&P (see Table 1)	
Demographic assumptions		
Mortality	95% CPM2014 Private Table projected with Scale B	Same
Retirement rates [2]	Table 3	Same
Termination rates [2]	Table 4	Same
Disability rates	Table 5	Same
Other assumptions		
Eligible spouse at retirement	90%	Same
Spousal age difference	Male 3 years older	Same

Notes:

[1] Return on asset assumption is net of any expenses paid by the trust.

[2] No terminations or retirements were assumed under the DCPP over the projection period.

Appendix D - Statement of Assumptions (Hydro One PRB and Inergi PRB)

The rates in the following table are on a per annum basis.

Measurement Date	**End of December 31 During Projection Period (2017-2023)**	**December 31, 2016 (as per year-end disclosures)**
Economic Assumptions		
Discount Rates:		
• Hydro One PRB	3.40%	3.90%
• Inergi PRB	3.40%	3.90%
Salary Increases		2.50%+M&P (see Table 2)
Management	2.50% + M&P (see Table 1)	
Society	2018-2019: 0.50% + M&P; 2020-2023: 2.00% + M&P; 2024 onwards: 2.50% + M&P (see Table 1)	
PWU	2018: 1.00% + M&P; 2019-2023: 2.00% + M&P 2024 onwards: 2.50% + M&P (see Table 1)	
Health Care Trend Rates		
• Prescription Drug	4.50% per annum	7.59% per annum in 2017 grading to 4.50% per annum after 2031
• Other Medical	7.37% per annum in 2017 grading to 4.50% per annum after 2031	7.59% per annum in 2017 grading to 4.50% per annum after 2031
• Hospital and Dental	3.00% per annum	4.50% per annum
• Vision Care	2.0% per annum through 2028 and 0% thereafter	Same
Per Capita Claim Costs	Please see Appendix A of the valuation presentation dated November 2017 for per capita claim costs and the corresponding aging factors and expense / tax rates.	Please see Appendix A of the valuation presentation dated November 2014 for per capita claim costs and the corresponding aging factors and expense / tax rates.
Demographic assumptions		
Mortality	95% CPM2014 Private Table projected with Scale B	Same
Retirement rates	Table 2	Same
Termination rates	Table 3	Same
Disability rates	Table 4	Same
Other assumptions		
Eligible spouse at retirement	90%	Same
Spousal age difference	Male 3 years older	Same

Appendix D - Statement of Assumptions (PEB)

The rates in the following table are on a per annum basis.

Measurement Date	**End of December 31 During Projection Period (2017-2023)**	**December 31, 2016 (as per year-end disclosures)**
Economic Assumptions		
Discount Rates:	3.40%	3.90%
Inflation on Disability Income Benefits	2.00%	same
Health Care Trend Rates		
• Medical	7.06% per annum in 2018 grading to 4.50% per annum after 2031	7.27% per annum in 2017 grading to 4.50% per annum after 2031
• Dental	4.50% per annum	Same
Per Capita Claim Costs		
• Medical	$8,075 in 2017	$7,200 in 2016
• Dental	$1,720 in 2017	$1,600 in 2016
Demographic assumptions		
Mortality	UP94 table projected generationally using Scale AA	Same
Disability termination rates	Based on the GLTD table from the 1988-1997 CIA Disability Termination Study, with adjustment at 2 year duration of disability to reflect Hydro One definition of disability of "any occupation"	Same
Incurred but not Reported (IBNR)	Estimated assuming a six month provision based on recent experience	Same

Table 1 — Salary Increases due to Movement within the Salary Structure

Age	First 4 Years of Employment	Subsequent Years
Under 25	7.5%	2.0%
25 - 29	5.5%	2.0%
30 - 34	3.5%	2.0%
35 - 39	3.5%	1.5%
40 – 44	3.5%	1.5%
45 - 49	2.0%	1.0%
50 - 54	2.0%	1.0%
55 - 59	1.0%	0.5%
60 & over	1.0%	0.0%

Table 2 — Salary Increases due to Movement within the Salary Structure (Prior)

Age	First 4 Years of Employment	Subsequent Years
Under 25	7.0%	1.0%
25 - 29	3.0%	1.0%
30 - 34	3.5%	1.5%
35 - 39	3.5%	1.5%
40 – 44	3.5%	2.0%
45 - 49	3.5%	1.5%
50 - 54	2.0%	1.5%
55 - 59	2.0%	1.5%
60 & over	2.0%	0.0%

Table 3 — Retirement rates

Age	Eligible for Unreduced Retirement: Based on points (82 or 85)	Eligible for Unreduced Retirement: 35 years of service and over	Not Eligible for Unreduced Retirement
Under 55	10%	30%	0%
55 to 59	15%	30%	5%
60 to 64	12%	30%	7%
65	50%	30%	20%
66 to 69	25%	30%	15%
70 and over	100%	100%	100%

Table 4 — Termination rates

Service (years)	Male & Female
Under 20	1%
20 and over	0%

Table 5 — Disability Rates

Age	Male & Female
Under 30	0%
30 to 35	0.105%
35 to 40	0.110%
40 to 45	0.115%
45 to 50	0.120%
50 to 55	0.295%
55 to 59	1.000%
60 and above	1.878%

Hydro One Pension Plan **APPENDIX A.1**

Projected 2017 to 2023 Accounting Under US GAAP

Figures in $000s

		Projections						
		2017	2018	2019	2020	2021	2022	2023
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	7,774,406	8,213,084	8,394,273	8,580,528	8,770,446	8,962,687	9,156,596
	Employer service cost (BOY)	146,693	172,035	177,593	181,720	184,595	186,993	191,265
	Interest cost	303,616	281,384	287,646	294,016	300,467	306,972	313,618
	Actuarial(gains)/losses	280,032	-	-	-	-	-	-
	Plan Participants' contributions	46,587	53,977	55,588	56,410	57,242	57,894	58,978
	Benefits Paid	(338,250)	(326,207)	(334,572)	(342,228)	(350,063)	(357,950)	(365,545)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	PBO at current fiscal year end	8,213,084	8,394,273	8,580,528	8,770,446	8,962,687	9,156,596	9,354,912
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	6,874,425	7,358,364	7,631,813	7,918,180	8,218,014	8,531,202	8,858,138
	Expected return on plan assets	441,393	471,846	489,467	507,919	527,215	547,364	568,469
	Actual gains/(losses) on assets	261,414	-	-	-	-	-	-
	Employer contributions	72,795	73,833	75,884	77,733	78,794	79,628	81,655
	Plan Participants' contributions	46,587	53,977	55,588	56,410	57,242	57,894	58,978
	Benefits paid	(338,250)	(326,207)	(334,572)	(342,228)	(350,063)	(357,950)	(365,545)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	7,358,364	7,631,813	7,918,180	8,218,014	8,531,202	8,858,138	9,201,695
C	**Amount recognized in the balance sheet**							
	Present value of obligations	8,213,084	8,394,273	8,580,528	8,770,446	8,962,687	9,156,596	9,354,912
	Fair value of plan assets	7,358,364	7,631,813	7,918,180	8,218,014	8,531,202	8,858,138	9,201,695
	Surplus (deficit)	(854,720)	(762,460)	(662,348)	(552,432)	(431,485)	(298,458)	(153,217)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	1,122,695	1,056,654	994,498	935,998	880,939	829,119	780,347
	Cumulative employer contributions in excess of benefit cost	267,975	294,194	332,150	383,566	449,454	530,661	627,130
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	(18,618)	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	(18,618)	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	(78,863)	(66,041)	(62,156)	(58,500)	(55,059)	(51,820)	(48,772)
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	(78,863)	(66,041)	(62,156)	(58,500)	(55,059)	(51,820)	(48,772)
	Credit (charge) to OCI in year	60,245	66,041	62,156	58,500	55,059	51,820	48,772
D	**Components of Benefit Cost**							
	Employer service cost	146,693	172,035	177,593	181,720	184,595	186,993	191,265
	Interest cost	303,616	281,384	287,646	294,016	300,467	306,972	313,618
	Expected return on plan assets	(441,393)	(471,846)	(489,467)	(507,919)	(527,215)	(547,364)	(568,469)
	Net prior service (credit)/cost amortization	-	-	-	-	-	-	-
	Net (gains)/loss amortization	78,863	66,041	62,156	58,500	55,059	51,820	48,772
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	87,779	47,614	37,928	26,317	12,906	(1,579)	(14,814)
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	1,182,940	1,122,695	1,056,654	994,498	935,998	880,939	829,119
	EARSL	15.00	17.00	17.00	17.00	17.00	17.00	17.00
	Amortization of (gains)/losses	78,863	66,041	62,156	58,500	55,059	51,820	48,772
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	282,959	267,975	294,194	332,150	383,566	449,454	530,661
	Pension expense recognized in P&L in the financial year	(87,779)	(47,614)	(37,928)	(26,317)	(12,906)	1,579	14,814
	Employer contributions made in the financial year	72,795	73,833	75,884	77,733	78,794	79,628	81,655
	Benefits paid directly by company in the financial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/divestitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	267,975	294,194	332,150	383,566	449,454	530,661	627,130
G	**Assumptions**							
	At beginning of period							
	Discount rate	3.90%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
	Expected rate of return on plan assets	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
	Rate of compensation increase	M&P (see table 2) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:
	- PWU	2.50%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%
	- Society	2.50%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%
	- Management	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	Mortality	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B
	Headcount Increase/(Reduction)	0%	10%	0%	-1%	-1%	-1%	-1%

Hydro One Supplemental Plan
Projected 2017 to 2023 Accounting Under US GAAP

APPENDIX A.2

Figures in $000s

		Projections						
		2017	2018	2019	2020	2021	2022	2023
A	**Change in Benefit Obligation**							
	PBO at prior fiscal year end	117,222	126,815	129,006	130,442	131,566	132,357	132,838
	Employer service cost	1,878	1,585	1,475	1,362	1,225	1,108	932
	Interest cost	4,578	4,303	4,362	4,402	4,432	4,451	4,458
	Actuarial(gains)/losses	6,557	-	-	-	-	-	-
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits Paid from the Company	(3,420)	(3,697)	(4,401)	(4,640)	(4,866)	(5,078)	(5,299)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Benefit obligation - end of period	126,815	129,006	130,442	131,566	132,357	132,838	132,929
B	**Change in Plan Assets**							
	Fair value of assets at prior fiscal year end	4,298	4,538	4,739	4,940	5,141	5,342	5,543
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions - benefits paid	3,420	3,697	4,401	4,640	4,866	5,078	5,299
	Employer contributions - Letter of credit	481	402	402	402	402	402	402
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits paid from the company	(3,420)	(3,697)	(4,401)	(4,640)	(4,866)	(5,078)	(5,299)
	Transfer payments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Market value of plan assets - end of period	4,538	4,739	4,940	5,141	5,342	5,543	5,744
C	**Amount recognized in the balance sheet**							
	Present value of obligations	126,815	129,006	130,442	131,566	132,357	132,838	132,929
	Fair value of plan assets	4,538	4,739	4,940	5,141	5,342	5,543	5,744
	Surplus (deficit)	(122,277)	(124,267)	(125,502)	(126,425)	(127,015)	(127,295)	(127,185)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	26,660	24,891	23,226	21,659	20,184	18,796	17,489
	Cumulative employer contributions in excess of benefit cost	(95,617)	(99,376)	(102,276)	(104,766)	(106,831)	(108,499)	(109,696)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	(6,557)	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	(6,557)	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	(1,453)	(1,568)	(1,464)	(1,366)	(1,274)	(1,187)	(1,106)
	- Past service credits/(costs) amortized in year	(10)	-	-	-	-	-	-
	Sub-total	(1,463)	(1,568)	(1,464)	(1,366)	(1,274)	(1,187)	(1,106)
	Credit (charge) to OCI in year	(5,094)	1,568	1,464	1,366	1,274	1,187	1,106
D	**Components of Benefit cost**							
	Employer service cost	1,878	1,585	1,475	1,362	1,225	1,108	932
	Expected letter of credit fee	481	402	402	402	402	402	402
	Interest cost	4,578	4,303	4,362	4,402	4,432	4,451	4,458
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service cost amortization	10	-	-	-	-	-	-
	Net loss/(gain) amortization	1,453	1,568	1,464	1,366	1,274	1,187	1,106
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	8,400	7,858	7,703	7,532	7,333	7,148	6,898
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	21,796	26,660	24,891	23,226	21,659	20,184	18,796
	EARSL	15.00	17.00	17.00	17.00	17.00	17.00	17.00
	Amortization of (gains)/losses	1,453	1,568	1,464	1,366	1,274	1,187	1,106
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(91,118)	(95,617)	(99,376)	(102,276)	(104,766)	(106,831)	(108,499)
	Pension expense recognized in P&L in the financial year	(8,400)	(7,858)	(7,703)	(7,532)	(7,333)	(7,148)	(6,898)
	Employer contributions made in the financial year	481	402	402	402	402	402	402
	Benefits paid directly by company in the financial year	3,420	3,697	4,401	4,640	4,866	5,078	5,299
	Net transfer in/(out) (including the effect of any acquisitions/divestitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(95,617)	(99,376)	(102,276)	(104,766)	(106,831)	(108,499)	(109,696)
G	**Assumptions**							
	At beginning of period							
	Discount rate	3.90%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate of compensation increase	M&P (see table 2) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:
	- PWU	2.50%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%
	- Society	2.50%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%
	- Management	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	Mortality	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B	95% of CPM Private projected generationally using scale CPM-B

Hydro One Pension Plan (RPP) and Hydro One Supplemental Plan (SPS/DSPS) **APPENDIX A.3**
Projected 2017 to 2023 Accounting Under US GAAP
Active / Inactive Split
Figures in $000s

RPP

	2017			2018			2019			2020			2021			2022			2023		
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	0	146,693	146,693	0	172,035	172,035	0	177,593	177,593	0	181,720	181,720	0	184,595	184,595	0	186,993	186,993	0	191,265	191,265
Interest cost	188,849	114,767	303,616	176,428	104,956	281,384	180,929	106,717	287,646	185,524	108,492	294,016	189,595	110,872	300,467	194,006	112,966	306,972	198,207	115,411	313,618
Expected return on plan assets	(274,546)	(166,847)	(441,393)	(295,847)	(175,998)	(471,846)	(307,875)	(181,592)	(489,467)	(320,497)	(187,422)	(507,919)	(332,673)	(194,542)	(527,215)	(345,934)	(201,430)	(547,364)	(359,272)	(209,197)	(568,469)
Amortization of past service cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of net (gain) loss	49,053	29,810	78,863	41,408	24,633	66,041	39,096	23,060	62,156	36,914	21,587	58,500	34,742	20,317	55,059	32,750	19,070	51,820	30,824	17,948	48,772
Curtailment (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Settlement (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefit cost recognized in the P&L account	(36,644)	124,423	87,779	(78,011)	125,626	47,615	(87,850)	125,778	37,928	(98,059)	124,377	26,318	(108,336)	121,242	12,906	(119,178)	117,599	(1,579)	(130,241)	115,427	(14,814)
Credit (charge) to OCI in year	37,472	22,773	60,245	41,408	24,633	66,041	39,096	23,060	62,156	36,914	21,587	58,500	34,742	20,317	55,059	32,750	19,070	51,820	30,824	17,948	48,772

SPS/DSPS

	2017			2018			2019			2020			2021			2022			2023		
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	0	1,878	1,878	0	1,585	1,585	0	1,475	1,475	0	1,362	1,362	0	1,225	1,225	0	1,108	1,108	0	932	932
Expected letter of credit fee	323	158	481	280	122	402	292	110	402	301	101	402	310	92	402	316	86	402	323	79	402
Interest cost	3,072	1,506	4,578	2,999	1,304	4,303	3,171	1,191	4,362	3,297	1,105	4,402	3,413	1,019	4,432	3,503	948	4,451	3,580	878	4,458
Expected return on plan assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of past service cost	10	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of net (gain) loss	975	478	1,453	1,093	475	1,568	1,064	400	1,464	1,022	343	1,366	981	293	1,274	934	253	1,187	888	218	1,106
Curtailment (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Special Termination Benefit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefit cost recognized in the P&L account	4,380	4,020	8,400	4,372	3,486	7,858	4,527	3,176	7,703	4,620	2,911	7,531	4,704	2,629	7,333	4,753	2,395	7,148	4,791	2,107	6,898
Credit (charge) to OCI in year	(3,418)	(1,676)	(5,094)	1,093	475	1,568	1,064	400	1,464	1,022	343	1,366	981	293	1,274	934	253	1,187	888	218	1,106

Hydro One Pension Plan (RPP) and Hydro One Supplemental Plan (SPS/DSPS)
Projected 2017 to 2023 Accounting Under US GAAP
Inergi / Non-Inergi Split
Figures in $000s

	2017			2018			2019			2020			2021			2022			2023		
Components of Benefit Cost	Inergi	Non-Inergi	Total	Inergi	Non-Inergi	Total	Inergi	Non-Inergi	Total	Inergi	Non-Inergi	Total	Inergi	Non-Inergi	Total	Inergi	Non-Inergi	Total	Inergi	Non-Inergi	Total
Current service cost	0	1,878	1,878	0	1,585	1,585	0	1,475	1,475	0	1,362	1,362	0	1,225	1,225	0	1,108	1,108	0	932	932
Expected letter of credit fee	6	475	481	5	397	402	5	397	402	5	397	402	4	398	402	4	398	402	4	398	402
Interest cost	60	4,518	4,578	52	4,251	4,303	52	4,310	4,362	53	4,349	4,402	49	4,383	4,432	40	4,411	4,451	40	4,418	4,458
Expected return on plan assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of past service cost	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of net (gain) loss	43	1,410	1,453	37	1,531	1,568	35	1,429	1,464	32	1,333	1,365	28	1,246	1,274	20	1,167	1,187	18	1,088	1,106
Curtailment (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Special Termination Benefit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total net periodic benefit cost recognized in the P&L account	109	8,291	8,400	94	7,764	7,858	92	7,611	7,703	90	7,441	7,531	81	7,252	7,333	64	7,084	7,148	62	6,836	6,898
Credit (charge) to OCI in year	(66)	(5,028)	(5,094)	37	1,531	1,568	35	1,429	1,464	32	1,333	1,365	28	1,246	1,274	20	1,167	1,187	18	1,088	1,106

Hydro One Inc. Non-Pension Post Retirement Benefit - Hydro One Only
Projected 2017 to 2023 Accounting under US GAAP

APPENDIX B.1

Figures in $000s

		2017	2018	2019	2020	2021	2022	2023
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	1,473,092	1,329,216	1,375,892	1,423,276	1,471,454	1,521,046	1,572,568
	Employer service cost (BOY)	40,936	40,122	40,959	41,741	43,117	45,134	47,932
	Interest cost	58,206	45,889	47,475	49,086	50,743	52,467	54,286
	Actuarial(gains)/losses	(199,907)	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(43,111)	(39,335)	(41,050)	(42,649)	(44,268)	(46,079)	(47,709)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	PBO at current fiscal year end	1,329,216	1,375,892	1,423,276	1,471,454	1,521,046	1,572,568	1,627,077
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	43,111	39,335	41,050	42,649	44,268	46,079	47,709
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(43,111)	(39,335)	(41,050)	(42,649)	(44,268)	(46,079)	(47,709)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	1,329,216	1,375,892	1,423,276	1,471,454	1,521,046	1,572,568	1,627,077
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(1,329,216)	(1,375,892)	(1,423,276)	(1,471,454)	(1,521,046)	(1,572,568)	(1,627,077)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	17,358	17,358	17,358	17,358	17,358	17,358	17,358
	Cumulative employer contributions in excess of benefi cost	(1,311,858)	(1,358,534)	(1,405,918)	(1,454,096)	(1,503,688)	(1,555,210)	(1,609,719)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	199,907	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	199,907	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	(4,892)	-	-	-	-	-	-
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	(4,892)	-	-	-	-	-	-
	Credit (charge) to OCI in year	204,799	-	-	-	-	-	-
D	**Components of Benefit Cost**							
	Employer service cost	40,936	40,122	40,959	41,741	43,117	45,134	47,932
	Interest cost	58,206	45,889	47,475	49,086	50,743	52,467	54,286
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	-	-	-	-	-	-	-
	Net (gains)/loss amortization	4,892	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	104,034	86,011	88,434	90,827	93,860	97,601	102,218
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	222,157	17,358	17,358	17,358	17,358	17,358	17,358
	EARSL	15.3	16.9	17.0	17.0	17.0	17	17
	Amortization of (gains)/losses	4,892	-	-	-	-	-	-
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(1,250,935)	(1,311,858)	(1,358,534)	(1,405,918)	(1,454,096)	(1,503,688)	(1,555,210)
	Benefit cost recognized in P&L in the financial year	(104,034)	(86,011)	(88,434)	(90,827)	(93,860)	(97,601)	(102,218)
	Employer contributions made in the financial year	43,111	39,335	41,050	42,649	44,268	46,079	47,709
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/diverstitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(1,311,858)	(1,358,534)	(1,405,918)	(1,454,096)	(1,503,688)	(1,555,210)	(1,609,719)
G	**Assumptions**							
	At beginning of period							
	Discount rate	3.90%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate of compensation increase		M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:
	- PWU	2.5%+M&P	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%
	- Society	2.5%+M&P	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%
	- Management	2.5%+M&P	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	Mortality	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B
	Headcount Change	0.00%	8.00%	0.00%	-1.00%	-1.00%	-1.00%	0.00%

Hydro One Inc. Non-Pension Post Retirement Benefit - Inergi Only
Projected 2017 to 2023 Accounting under US GAAP

APPENDIX B.2

Figures in $000s

		2017	2018	2019	2020	2021	2022	2023
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	39,947	35,599	35,821	35,993	36,101	36,159	36,161
	Employer service cost (BOY)	-	-	-	-	-	-	-
	Interest cost	1,538	1,194	1,200	1,205	1,208	1,209	1,208
	Actuarial(gains)/losses	(4,876)	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(1,010)	(972)	(1,028)	(1,097)	(1,150)	(1,207)	(1,271)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	PBO at current fiscal year end	35,599	35,821	35,993	36,101	36,159	36,161	36,098
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	1,010	972	1,028	1,097	1,150	1,207	1,271
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(1,010)	(972)	(1,028)	(1,097)	(1,150)	(1,207)	(1,271)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	35,599	35,821	35,993	36,101	36,159	36,161	36,098
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(35,599)	(35,821)	(35,993)	(36,101)	(36,159)	(36,161)	(36,098)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	(1,551)	(1,551)	(1,551)	(1,551)	(1,551)	(1,551)	(1,551)
	Cumulative employer contributions in excess of benefi cost	(37,150)	(37,372)	(37,544)	(37,652)	(37,710)	(37,712)	(37,649)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	4,876	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	4,876	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	-	-	-	-	-	-	-
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-
	Credit (charge) to OCI in year	4,876	-	-	-	-	-	-
D	**Components of Benefit Cost**							
	Employer service cost	-	-	-	-	-	-	-
	Interest cost	1,538	1,194	1,200	1,205	1,208	1,209	1,208
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	-	-	-	-	-	-	-
	Net (gains)/loss amortization	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	1,538	1,194	1,200	1,205	1,208	1,209	1,208
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	3,325	(1,551)	(1,551)	(1,551)	(1,551)	(1,551)	(1,551)
	EARSL	9.8	7.9	7.5	7.0	6.6	6	6
	Amortization of (gains)/losses	-	-	-	-	-	-	-
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(36,622)	(37,150)	(37,372)	(37,544)	(37,652)	(37,710)	(37,712)
	Benefit cost recognized in P&L in the financial year	(1,538)	(1,194)	(1,200)	(1,205)	(1,208)	(1,209)	(1,208)
	Employer contributions made in the financial year	1,010	972	1,028	1,097	1,150	1,207	1,271
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/diverstitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(37,150)	(37,372)	(37,544)	(37,652)	(37,710)	(37,712)	(37,649)
G	**Assumptions**							
	At beginning of period							
	Discount rate	3.90%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate of compensation increase		M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:
	- PWU	2.5%+M&P	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%	2018: 1.0%; 2019-2023: 2.0%, 2024 onwards: 2.5%
	- Society	2.5%+M&P	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%	2018-2019: 0.5%; 2020-2023: 2.0%, 2024 onwards: 2.5%
	- Management	2.5%+M&P	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	Mortality	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B
	Headcount Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Hydro One Inc. Non-Pension Post Retirement Benefit - Hydro One + Inergi
Projected 2017 to 2023 Accounting under US GAAP

APPENDIX B.3

Figures in $000s

		2017	2018	2019	2020	2021	2022	2023
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	1,513,039	1,364,815	1,411,713	1,459,269	1,507,555	1,557,205	1,608,729
	Employer service cost (BOY)	40,936	40,122	40,959	41,741	43,117	45,134	47,932
	Interest cost	59,744	47,083	48,675	50,291	51,951	53,676	55,494
	Actuarial(gains)/losses	(204,783)	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(44,121)	(40,307)	(42,078)	(43,746)	(45,418)	(47,286)	(48,980)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	PBO at current fiscal year end	1,364,815	1,411,713	1,459,269	1,507,555	1,557,205	1,608,729	1,663,175
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	44,121	40,307	42,078	43,746	45,418	47,286	48,980
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(44,121)	(40,307)	(42,078)	(43,746)	(45,418)	(47,286)	(48,980)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	1,364,815	1,411,713	1,459,269	1,507,555	1,557,205	1,608,729	1,663,175
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(1,364,815)	(1,411,713)	(1,459,269)	(1,507,555)	(1,557,205)	(1,608,729)	(1,663,175)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	15,807	15,807	15,807	15,807	15,807	15,807	15,807
	Cumulative employer contributions in excess of benefit cost	(1,349,008)	(1,395,906)	(1,443,462)	(1,491,748)	(1,541,398)	(1,592,922)	(1,647,368)
	Annual charges to OCI	-	-	-	-	-	-	-
	- Net actuarial gains/(losses) incurred in year	204,783	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	204,783	-	-	-	-	-	-
	LESS	-	-	-	-	-	-	-
	- Net actuarial gains/(losses) amortized in year	(4,892)	-	-	-	-	-	-
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	(4,892)	-	-	-	-	-	-
	Credit (charge) to OCI in year	209,675	-	-	-	-	-	-
D	**Components of Benefit Cost**							
	Employer service cost	40,936	40,122	40,959	41,741	43,117	45,134	47,932
	Interest cost	59,744	47,083	48,675	50,291	51,951	53,676	55,494
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	-	-	-	-	-	-	-
	Net (gains)/loss amortization	4,892	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	105,572	87,205	89,634	92,032	95,068	98,810	103,426
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	225,482	15,807	15,807	15,807	15,807	15,807	15,807
	EARSL	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Amortization of (gains)/losses	4,892	-	-	-	-	-	-
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(1,287,557)	(1,349,008)	(1,395,906)	(1,443,462)	(1,491,748)	(1,541,398)	(1,592,922)
	Benefit cost recognized in P&L in the financial year	(105,572)	(87,205)	(89,634)	(92,032)	(95,068)	(98,810)	(103,426)
	Employer contributions made in the financial year	44,121	40,307	42,078	43,746	45,418	47,286	48,980
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/diverstitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(1,349,008)	(1,395,906)	(1,443,462)	(1,491,748)	(1,541,398)	(1,592,922)	(1,647,368)
G	**Assumptions**							
	At beginning of period							
	Discount rate	3.90%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate of compensation increase		M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:	M&P (see table 1) plus:
			2018: 1.0%;	2018: 1.0%;	2018: 1.0%;	2018: 1.0%;	2018: 1.0%;	2018: 1.0%;
			2019-2023: 2.0%,	2019-2023: 2.0%,	2019-2023: 2.0%,	2019-2023: 2.0%,	2019-2023: 2.0%,	2019-2023: 2.0%,
	- PWU	2.5%+M&P	2024 onwards: 2.5%	2024 onwards: 2.5%	2024 onwards: 2.5%	2024 onwards: 2.5%	2024 onwards: 2.5%	2024 onwards: 2.5%
			2018-2019: 0.5%;	2018-2019: 0.5%;	2018-2019: 0.5%;	2018-2019: 0.5%;	2018-2019: 0.5%;	2018-2019: 0.5%;
			2020-2023: 2.0%,	2020-2023: 2.0%,	2020-2023: 2.0%,	2020-2023: 2.0%,	2020-2023: 2.0%,	2020-2023: 2.0%,
	- Society	2.5%+M&P	2024 onwards: 2.5%	2024 onwards: 2.5%	2024 onwards: 2.5%	2024 onwards: 2.5%	2024 onwards: 2.5%	2024 onwards: 2.5%
	- Management	2.5%+M&P	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
	Mortality	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B	95% 2014 CPM Private; projected generationally using scale CPM-B
	Headcount Reduction	0.00%	8.00%	0.00%	-1.00%	-1.00%	-1.00%	0.00%

Hydro One Inc. Post Employment Benefits
Projected 2017 to 2023 Accounting under US GAAP

APPENDIX B.4

Figures in $000s

		Projections						
		2017	2018	2019	2020	2021	2022	2023
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	59,702	61,794	62,490	63,167	63,750	64,232	64,606
	Employer service cost (BOY)	5,783	6,737	6,928	7,050	7,173	7,295	7,491
	Interest cost	2,398	2,190	2,216	2,239	2,259	2,276	2,291
	Actuarial(gains)/losses	1,911	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(8,000)	(8,231)	(8,467)	(8,706)	(8,950)	(9,197)	(9,448)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	PBO at current fiscal year end	61,794	62,490	63,167	63,750	64,232	64,606	64,940
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	8,000	8,231	8,467	8,706	8,950	9,197	9,448
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(8,000)	(8,231)	(8,467)	(8,706)	(8,950)	(9,197)	(9,448)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	61,794	62,490	63,167	63,750	64,232	64,606	64,940
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(61,794)	(62,490)	(63,167)	(63,750)	(64,232)	(64,606)	(64,940)
	Unrecognized past service cost (benefit)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Unrecognized net actuarial (gains)/losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cumulative employer contributions in excess of benefi cost	(61,794)	(62,490)	(63,167)	(63,750)	(64,232)	(64,606)	(64,940)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	- Past service credits/(costs) incurred in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Sub-total	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	LESS							
	- Net actuarial gains/(losses) amortized in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	- Past service credits/(costs) amortized in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Sub-total	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Credit (charge) to OCI in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D	**Components of Benefit Cost**							
	Employer service cost	5,783	6,737	6,928	7,050	7,173	7,295	7,491
	Interest cost	2,398	2,190	2,216	2,239	2,259	2,276	2,291
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	-	-	-	-	-	-	-
	Net (gains)/loss amortization	1,911	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	10,092	8,927	9,144	9,289	9,432	9,571	9,782
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	EARSL	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Amortization of (gains)/losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(59,702)	(61,794)	(62,490)	(63,167)	(63,750)	(64,232)	(64,606)
	Benefit cost recognized in P&L in the financial year	(10,092)	(8,927)	(9,144)	(9,289)	(9,432)	(9,571)	(9,782)
	Employer contributions made in the financial year	8,000	8,231	8,467	8,706	8,950	9,197	9,448
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/diverstitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(61,794)	(62,490)	(63,167)	(63,750)	(64,232)	(64,606)	(64,940)
G	**Assumptions**							
	At beginning of period							
	Discount rate	3.90%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Rate of compensation increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
	Termination Rates	GLTD table from 1988-1997 CIA Disability Termination Study, with adjustment at 2 year duration of disability	GLTD table from 1988-1997 CIA Disability Termination Study, with adjustment at 2 year duration of disability	GLTD table from 1988-1997 CIA Disability Termination Study, with adjustment at 2 year duration of disability	GLTD table from 1988-1997 CIA Disability Termination Study, with adjustment at 2 year duration of disability	GLTD table from 1988-1997 CIA Disability Termination Study, with adjustment at 2 year duration of disability	GLTD table from 1988-1997 CIA Disability Termination Study, with adjustment at 2 year duration of disability	GLTD table from 1988-1997 CIA Disability Termination Study, with adjustment at 2 year duration of disability

Hydro One Inc. Non-Pension Post Retirement Benefit **APPENDIX C**
Projected 2017 to 2023 Accounting under US GAAP
Active / Inactive Split
Figures in $000s

Projected OPRB Expense - Hydro One

		2017			2018			2019			2020			2021			2022			2023	
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	-	40,936	40,936	-	40,122	40,122	-	40,959	40,959	-	41,741	41,741	-	43,117	43,117	-	45,134	45,134	-	47,932	47,932
Interest cost	32,770	25,436	58,206	26,065	19,824	45,889	26,871	20,604	47,475	27,783	21,303	49,086	28,670	22,073	50,743	29,486	22,981	52,467	30,454	23,832	54,286
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of past service cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of net (gain) loss	2,754	2,138	4,892	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefit cost recognized in the P&L account	35,524	68,510	104,034	26,065	59,946	86,011	26,871	61,563	88,434	27,783	63,044	90,827	28,670	65,190	93,860	29,486	68,115	97,601	30,454	71,764	102,218
Credit (charge) to OCI in year	115,302	89,497	204,799	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Projected OPRB Expense - Inergi

		2017			2018			2019			2020			2021			2022			2023	
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						
Interest cost	1,030	508	1,538	829	365	1,194	863	337	1,200	899	306	1,205	939	269	1,208	970	239	1,209	997	211	1,208
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						
Amortization of past service cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						
Amortization of net (gain) loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-						
Total benefit cost recognized in the P&L account	1,030	508	1,538	829	365	1,194	863	337	1,200	899	306	1,205	939	269	1,208	970	239	1,209	997	211	1,208
Credit (charge) to OCI in year	3,267	1,609	4,876	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Projected OPRB Expense - Total (Hydro One Inc. + Inergi)

		2017			2018			2019			2020			2021			2022			2023	
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	-	40,936	40,936	-	40,122	40,122	-	40,959	40,959	-	41,741	41,741	-	43,117	43,117	-	45,134	45,134	-	47,932	47,932
Interest cost	33,800	25,944	59,744	26,894	20,189	47,083	27,734	20,941	48,675	28,682	21,609	50,291	29,609	22,342	51,951	30,456	23,220	53,676	31,451	24,043	55,494
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of past service cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of net (gain) loss	2,754	2,138	4,892	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefit cost recognized in the P&L account	36,554	69,018	105,572	26,894	60,311	87,205	27,734	61,900	89,634	28,682	63,350	92,032	29,609	65,459	95,068	30,456	68,354	98,810	31,451	71,975	103,426
Credit (charge) to OCI in year	118,569	91,106	209,675	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Hydro One Inc. Post Employment Benefit
Projected 2017 to 2023 Accounting under US GAAP
Active / Inactive Split
Figures in $000s

Projected PEB Expense

		2017			2018			2019			2020			2021			2022			2023	
Components of Benefit Cost	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total	Inactive	Active	Total
Current service cost	5,783	-	5,783	6,737	-	6,737	6,928	-	6,928	7,050	-	7,050	7,173	-	7,173	7,295	-	7,295	7,491	-	7,491
Interest cost	2,398	-	2,398	2,190	-	2,190	2,216	-	2,216	2,239	-	2,239	2,259	-	2,259	2,276	-	2,276	2,291	-	2,291
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of past service cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of net (gain) loss	1,911	-	1,911	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefit cost recognized in the P&L account	10,092	-	10,092	8,927	-	8,927	9,144	-	9,144	9,289	-	9,289	9,432	-	9,432	9,571	-	9,571	9,782	-	9,782
Credit (charge) to OCI in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

OEB INTERROGATORY #206

Reference:

F-05-01 p.10

Interrogatory:

At the above reference, Hydro One describes the three potential outcomes with respect to its proposals to address the new US GAAP accounting standard that will limit how much of its OPEB costs it is able to capitalize.

a) In regard to the OEB approving the continuance of the deferral account option. Please confirm that the intention of the account will be to continue to only capture the portion of the OPEB costs that can no longer be capitalized? Or is the intention to also include a return on rate base component that would have been earned on these amounts had they had been included in rate base.

b) In regard to the OEB disallowing both the capitalization option and the continued use of the deferral account, how will the amounts already included in the account for 2018 be dealt with? Will Hydro One then be asking for disposition of the account balance as at December 31, 2018, or will it defer disposition to a future period?

Response:

a) The intention is to only capture the portion of the OPEB costs that can no longer be capitalized.

   Hydro One notes that as indicated in Exhibit C, Tab 1, Schedule 1 (Rate Base) page 4 and Exhibit F, Tab 5, Schedule 1 (Pension and OPEB Costs) page 10; capital expenditures/in-service additions are based on the assumption of continued capitalization of the non-service cost component. However, for the purpose of revenue requirement calculation these amounts were removed from rate base (under the transfers/other line in Table 4 of Exhibit C, Tab 1, Schedule 1). At the time of creating the application an assumption of 1:1 of capital expenditure to in-service additions was made. Additionally, outdated amounts were used to account for non-service cost component of OPEB (see Table 4 of Exhibit C, Tab 1, Schedule 1).

To reflect the OPEB amounts as provided in Exhibit I, Tab 01, Schedule OEB-221 part g), Hydro One is seeking to update revenue requirement for 2020-2022 using the more appropriate assumptions for in-service additions. The impact would be an increase to revenue requirement by the following amounts:

OPEB Update ($M)	**2020**	**2021**	**2023**
Revenue Requirement Impact	0.7	2.0	2.6

b) The current application is proposing the disposition of deferral and variance accounts balances based on 2018 audited actuals. Consistent with this approach Hydro One will request disposition or this account balance for 2018 audited actuals. Any amounts accumulated for 2019 will be disposed of as part of the next rebasing application or potentially during the 2021 or 2022 annual updates. Exhibit I, Tab 01, Schedule OEB-221 part e) explains further in the event that both options are disallowed, specifically the continued use of the account and capitalization would result in the amount being added to OM&A.

OEB INTERROGATORY #207

Reference:
F-07-02-01

Interrogatory:
At the above reference, Hydro One provides its detailed regulatory tax calculations for the period 2019-2022, including the sharing of the tax benefits that resulted from Hydro One's IPO. Hydro One shares those benefits based on a ratio that allocates 63.5% of the benefits in favour of the shareholder.

In the November 9, 2017 Decision and Order for EB-2016-0160 (H1 Tx), the OEB multiplied the benefits follow costs allocation factor in favour of shareholders by the Grossed Up Regulatory Taxes for 2017 and 2018 respectively in order to arrive at the regulatory taxes included in the revenue requirement for each year. The Grossed Up Regulatory Tax balance that was used in that calculation for each year represented the regulatory taxes that would have been included in the revenue requirement had the tax benefits from the IPO been allocated 100% in favour of the shareholder. This calculation that was used to arrive at the final regulatory tax balance for both 2017 and 2018 was not contested and the resulting regulatory taxes were included in rates approved for the respective years.

a) It appears that Hydro One has deviated from the above approved methodology within its tax calculations in the current proceeding, please explain why that is the case and why Hydro One's current proposal with respect to calculating the allocation of the tax benefits is more appropriate.

b) Please provide a table that compares annually, the tax benefits allocated to the ratepayers/shareholder under Hydro One's current proposal within this application versus the methodology used in the EB-2016-0160 Decision and Order (as described above).

Response:
a) The methodology used in the current application for allocating tax benefits to transmission ratepayers is consistent with the Draft Rate Order for Distribution that was subsequently approved by the OEB (EB-2017-0049).

The current proposal for allocating tax benefits to rate-payers is more accurate than the methodology used in the examples included in the Decision and Order in EB-2016-0160 dated September 28, 2017[1] (the "Original Decision") as the tax benefits are derived from the FMV bump[2], which is realized through a higher capital cost allowance (CCA) in the future. In the Original Decision, the OEB stated that "the difference in value between the sale price and the tax cost (FMV Bump) is available to the asset owner to provide CCA related tax savings in the future"[3], confirming that the tax savings from the FMV Bump is realized through CCA deductions in future years as provided under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) (collectively the "Income Tax Act"). Consequently, in this Application as in the Draft Rate Order in EB-2017-0049, Hydro One has properly implemented the Original Decision by applying the Prescribed Allocation Factor[4] to the maximum annual CCA allowable under the Income Tax Act related to the increase in tax basis from the FMV bump. With Hydro One's approach, the benefit from the tax sharing closely aligns to the tax savings derived from the maximum annual CCA claim allowable under the Income Tax Act.

The Original Decision allocated the benefit by applying the Prescribed Allocation Factor to the grossed-up regulatory income tax; however, this approach implicitly assumes that the annual taxable income (which is the basis from which Hydro One derived regulatory taxes) is the same as the CCA deductions relating to the FMV Bump. This is not the case as there is no relationship between taxable income and the maximum allowable CCA deductions relating to the FMV Bump.

Consequently, Hydro One's proposed method of allocating the tax benefits in this Application as in the Draft Rate Order in EB-2017-0049 provides for a better matching between the tax attributes that gave rise to the future tax savings and the manner in which the future tax savings will be realized when compared to the allocation examples included in the Original Decision.

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[1] EB-2016-0160 Decision and Order dated September 28, 2017
[2]FMV Bump is the increase in the tax basis of assets as a result the deemed disposition arising for the IPO. The increase in tax basis provides additional tax deductions in the form of capital cost allowance in the future.
[3] Ibid, page 83
[4] Table 15-3 "Actual FMV Sales and Payment Ratios" in the decision and order (EB-2016-0160) dated September 28, 2017, (page 102)

Further details are provided in Section 4 of Hydro One's DRO reply submission in EB-2017-0049 dated May 9, 2019.

b) Hydro One has followed the requirement in the Original Decision to return a portion of the taxable benefit arising from the FMV bump based on the OEB's Prescribed Allocation Factor. However, Hydro One implemented the Original Decision by applying the prescribed allocation factor to the CCA deduction related to the FMV Bump rather than to the grossed-up regulatory taxes. Consequently, the total tax benefits to be shared with rate payers over time is the same and the differences in the annual amounts solely relate to the timing of when are derived and allocated to the ratepayers.

Please see the table below for the requested comparison of CCA based on the current proposed methodology vs. the Original Decision (EB-2016-0160). The Deferred Tax Asset sharing numbers below are based upon the taxes that were submitted as part of the blue page update.

Deferred Tax Sharing Allocation	2019	2020	2021	2022	Cumulative
- Current Methodology - CCA	(35.6)	(32.8)	(30.5)	(28.4)	(127.3)
- EB-2016-0160 - Decision	(26.9)	(29.6)	(32.8)	(34.0)	(123.4)
Difference	(8.69)	(3.18)	2.32	5.65	(3.89)

OEB INTERROGATORY #208

Reference:
F-07-02-02A

Interrogatory:
At the above reference, Hydro One provides its CCA continuity schedule for the period 2019-2022

The Government of Canada's 2018 Fall Economic Statement was tabled on November 21, 2018. It proposes the following measures for certain eligible property acquired after November 20, 2018:

- Accelerated Investment Incentive – Providing an enhanced first-year allowance for certain eligible property that is subject to the Capital Cost Allowance (CCA) rules. In general, the incentive will be made up of two elements:
  - applying the prescribed CCA rate for a class to up to one-and-a-half times the net addition to the class for the year
  - suspending the existing CCA half-year rule (and equivalent rules for Canadian vessels and class 13 property).

- Full Expensing for Manufacturers and Processors – Allowing businesses to immediately write off the full cost of machinery and equipment used for the manufacturing or processing of goods (class 53).

- Full Expensing for Clean Energy Investments – Allowing businesses to immediately write off the full cost of specified clean energy equipment (classes 43.1 and 43.2).

The Federal Government’s 2019 Budget, announced on March 19, 2019 confirmed the Government’s intention to proceed with the above proposals.

a) Please state whether Hydro One has reflected the impact of the new accelerated CCA rules within its CCA calculations for the period 2019-2022 that are currently on the record of this proceeding.

b) If the accelerated CCA rules are not reflected, then please explain why this is the case. Please also provide updated detailed PILs calculations and supporting CCA tables for the period 2019-2022 that reflect the new accelerated CCA rules.

c) Since the accelerated CCA rules are effective from November 20, 2018, please confirm if Hydro One has prepared its 2018 corporate tax return using these new CCA rules. If not, please explain why that is the case.

d) Given that the approved 2018 and 2019 rates were underpinned by the old CCA rules, how is Hydro One planning to make ratepayers whole with respect to the 2018 and 2019 revenue requirement impact associated with the difference between the PILs amounts included in rates for those years and the PILS amounts that would have been included in rates had they been based on the new accelerated CCA rules.

e) Please provide the calculations for 2018 and 2019 revenue requirement impact had the PILs for those years been calculated using the new accelerated CCA rules.

f) If Hydro One is not planning to make ratepayers whole with respect to the 2018 and 2019 revenue requirement impact associated with the change in CCA rules, then please explain why such an approach would be appropriate.

g) How does Hydro One intend to treat expenditures made under long-term capital projects based on the new rules? For example, if Hydro One had undertook and incurred expenditure for a capital project that commenced before the new rules took effect (and continued to carry-on after the new rules took effect), will the expenditures incurred before and after the effective date of the new rules be treated differently for this project for purposes of calculating CCA once the related asset is put into service?

Response:

Please note that Hydro One interpreted PILS to refer to income tax expense as Hydro One is now subject to income tax under the federal tax regime.

a) The impact of the Accelerated Investment Incentive **(Accelerated CCA**) is not included in Hydro One's pre-filed evidence for the reasons set out below. By way of background, Accelerated CCA provides an enhanced first-year tax deduction for capital property subject to CCA rules. Accelerated CCA will suspend the half-year rule and allow for a deduction of one and half times the normal CCA rate for assets in-serviced after November 20, 2018 that also become available for use before 2028 (subject to a phase-out for property that becomes available for use after 2023).

b) Hydro One's policy is to reflect changes in tax legislation after they are enacted into law. Accelerated CCA was enacted on June 21, 2019, after Hydro One had filed its update to this Application on March 21, 2019.

Please refer to Attachment 1 to this Exhibit for the taxable income calculations and supporting CCA calculations for 2019-2022 that incorporate the Accelerated CCA rules.

As part of this IR response, Hydro One is proposing to update the revenue requirement to reflect Accelerated CCA rules. The change in revenue requirement as a result of Accelerated CCA is estimated to be as follows:

	2020	2021	2022
Revenue Requirement for Tax - before Accelerated CCA	48.3	59.4	64.8
Revenue Requirement for Tax - after Accelerated CCA	24.8	25.0	37.7
Reduction in Revenue Requirement	(23.5)	(34.4)	(27.1)

c) Hydro One did not prepare its 2018 corporate tax return using the new Accelerated CCA rules. For 2018, Accelerated CCA is only available for those project costs that are incurred after November 20, 2018 and placed in-service before December 31, 2018. Hydro One's projects generally have long lead-times between commencement and in-service and do not typically involve the incurrence of high costs just prior to going into service. As such, for projects in-serviced between November 20, 2018 and year-end 2018, it was considered that substantially all of the costs would have been incurred prior to November 20, 2018 and would therefore not qualify for accelerated depreciation. Consequently, as the portion of assets eligible for Accelerated CCA in 2018 was expected to be immaterial, Hydro One determined that it would not prepare its 2018 corporate tax return using the new Accelerated CCA rules.

In light of the considerations described above and given the timing of the legislation coming into force vis a vis the filing date (the legislation was enacted on June 21, 2019 and the filing date was June 30), Accelerated CCA was not claimed in the 2018 tax returns. The total CCA deduction available over the life of the asset is the same under the new rules, as Accelerated CCA simply increases the amount that may be claimed in the first year. As such, to the extent accelerated CCA has not been claimed for prior years, additional deductions will be available in subsequent years.

d) The differences in revenue requirement due to accelerated CCA will be recorded in a variance account (Account 1592) starting in 2019 and returned to ratepayers at a future date in a manner as determined by the OEB. Please refer to part e) below in regards to 2018.

e) As discussed in part c) above, it is very unlikely that the projects in-serviced between November 20, 2018 and December 31, 2018 would qualify for Accelerated CCA. Therefore, the revenue requirement impact for 2018 is expected to be immaterial and has not been quantified. In light of the OEB accounting guidance on Bill C-97 Accelerated CCA dated July 25, 2019, Hydro One is evaluating the 2018 benefits of Accelerated CCA.

The revenue requirement for 2019 is estimated to be lower by $18.3M if taxes were calculated using Accelerated CCA. This calculation assumes that 47% of the assets qualify for Accelerated CCA, which is subject to change as the information to determine the assets qualifying for Accelerated CCA will not available until 2019 year-end.

	2019	
CCA	545.36	*
CCA - Acclerated CCA	596.07	*
Additional CCA	(50.72)	
Tax Rate	26.5%	
Tax Effected	(13.44)	
Gross up	(18.29)	

*2019 was an inflationary increase from 2018. Therefore, 2018 CCA schedules used to calculated the 2019 impact of accelerated CCA

f) Please see part d) above for more information.

g) For projects in-serviced after November 20, 2018, only costs that were incurred after this date would be eligible for accelerated CCA. Please refer to part c) above for additional information.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Utility Income Taxes
Bridge Year (2019) &Test Years (2020 to 2022)
Year Ending December 31
($ Millions)

Line No.	Particulars	2019 (a)	2020 (b)	2021 (c)	2022 (d)
	Determination of Taxable Income				
1	Regulatory Net Income (before tax)	$ 498.1	$ 525.6	$ 560.2	$ 593.1
2	Reduction in Net Income due to lower taxes	(16.8)	(23.6)	(34.4)	(27.2)
		481.4	502.0	525.8	565.9
	Book to Tax Adjustments:				
3	Other Post Employment Benefits expense	20.6	21.1	21.5	21.1
4	Other Post Employment Benefits payments	(27.0)	(28.7)	(30.7)	(31.3)
5	Depreciation and amortization	467.7	474.6	505.2	530.9
7	Capital Cost Allowance	(667.5) *	(682.2) *	(735.2) *	(757.4) *
8	Removal costs	(3.3)	(3.3)	(3.3)	(3.3)
9	Environmental costs	(6.8)	(12.6)	(17.4)	(19.3)
10	Hedge loss - amortization	0.0	0.0	0.0	0.0
11	Non-deductible meals & entertainment	3.4	3.4	3.4	3.4
12	Capital amounts expensed under $2K	4.3	4.3	4.3	4.3
13	Research & Development ITC	0.0	0.0	0.0	0.0
14	Federal apprenticeship & education credits	0.3	0.3	0.4	0.3
15	Capitalized overhead costs	(33.2)	(34.7)	(35.7)	(36.0)
16	Capitalized pension costs	(25.9)	(27.9)	(30.1)	(30.2)
17	Debt Issuance costs - amortization	2.0	2.2	2.2	2.3
18	Debt Issuance costs - 21e deduction	(3.5)	(3.8)	(3.2)	(4.0)
19	Premium/Discount - amortization	(0.3)	(0.4)	(0.4)	(0.2)
20	Bond discount deduction	(0.1)	(0.0)	(0.1)	0.0
21	Non-deductible LTIP	2.7	2.7	2.8	2.8
22	Capital Contribution True-Up Adjustment	0.0	0.0	0.0	0.0
23	Other	1.5	1.4	1.3	1.2
		$ (265.1)	$ (283.6)	$ (315.1)	$ (315.4)
24	Regulatory Taxable Income	$ 216.2	$ 218.4	$ 210.6	$ 250.5
25	Corporate Income Tax Rate	% 26.50	% 26.50	% 26.50	% 26.50
26	Subtotal	$ 57.3	$ 57.9	$ 55.8	$ 66.4
27	Less: R&D ITC / Ontario education credits	(0.3)	(0.3)	(0.4)	(0.3)
28	Regulatory Income Tax	$ 57.0	$ 57.5	$ 55.5	$ 66.0
29	Less: Deferred Tax Asset Sharing	(35.6)	(32.8)	(30.5)	(28.4)
30	Revenue Requirement Income Tax*	$ 21.4	$ 24.8	$ 25.0	$ 37.7
	Tax Rates				
31	Federal Tax	% 15.00	% 15.00	% 15.00	% 15.00
32	Provincial Tax	% 11.50	% 11.50	% 11.50	% 11.50
33	Total Tax Rate	% 26.50	% 26.50	% 26.50	% 26.50

* Accelerated CCA is only available for assets in serviced after November 20, 2018, to the extend that costs associated with such assets are incurred after this date. As such, not all assets in serviced subsequent to November 20, 2018

CALCULATION OF CAPITAL COST ALLOWANCE
BRIDGE (2019) AND TEST (2020 - 2022) YEARS

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost Allowance (CCA)
2019 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

CCA Class	Opening UCC *	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,906.0	21.1	1927.1	10.5	1916.5	4%	77.1	1850.0
2	444.9	0.0	444.9	0.0	444.9	6%	26.7	418.2
3	216.9	0.0	216.9	0.0	216.9	5%	10.8	206.1
6	61.1	0.0	61.1	0.0	61.1	10%	6.1	55.0
7	0.0	0.0	0.0	0.0	0.0	15%	0.0	0.0
8	132.2	60.6	192.8	30.3	162.5	20%	38.2	154.6
9	0.4	0.0	0.4	0.0	0.4	25%	0.1	0.3
10	34.4	11.0	45.4	5.5	39.9	30%	13.5	31.9
12	13.5	47.7	61.2	23.8	37.4	100%	48.6	12.6
13	9.9	(1.4)	8.5	0.0	9.9	0%	1.3	7.3
14.1 (ECE)**	39.0	0.0	39.0	0.0	39.0	7%	2.7	36.3
14.1 (Post-2017)	9.5	6.0	15.5	3.0	12.5	5%	0.8	14.7
17	112.4	1.1	113.5	0.6	113.0	8%	9.1	104.5
35	0.1	0.0	0.1	0.0	0.1	7%	0.0	0.1
42	64.9	0.0	64.9	0.0	64.9	12%	7.8	57.1
45	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0
46	10.0	0.0	10.0	0.0	10.0	30%	3.0	7.0
47	3,909.3	708.4	4617.7	354.2	4263.5	8%	367.7	4250.0
50	110.6	3.4	114.0	1.7	112.3	55%	62.6	51.4
52	-	0.0	0.0	0.0	0.0	100%	0.0	0.0
Sub Total	7,075.2	857.9	7,933.2	429.7	7,504.9		676.1	7,257.1
					Not included in RR		(8.6)	***
					Total CCA for RR		667.5	

Notes:

* The Opening Undepreciated Capital Cost ("UCC") numbers are rolled forward based on the 2018 Tax Provision.

** The Eligible Capital Expenditures ("ECE") transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027.

*** This is the CCA for items such as CCRA True ups and Project Cancellation Costs. As these items are not included in rates, the tax benefits associated should also be excluded from rates.

Witness: Selma Yam

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost Allowance (CCA)
2020 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,850.0	28.9	1879.0	14.5	1864.5	0.0	75.6	1803.4
2	418.2	0.0	418.2	0.0	418.2	0.1	25.1	393.1
3	206.1	0.0	206.1	0.0	206.1	0.1	10.3	195.8
6	55.0	0.0	55.0	0.0	55.0	0.1	5.5	49.5
7	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0
8	154.6	48.4	203.0	24.2	178.8	0.2	44.3	158.7
9	0.3	0.0	0.3	0.0	0.3	0.3	0.1	0.2
10	31.9	10.8	42.7	5.4	37.3	0.3	14.1	28.7
12	12.6	21.8	34.4	10.9	23.5	1.0	33.1	1.3
13	7.3	(0.7)	6.6	(0.3)	6.9	0.0	0.9	5.7
14.1 (ECE)**	36.3	0.0	36.3	0.0	36.3	0.1	2.5	33.7
14.1 (Post-2017)	14.7	8.5	23.2	4.2	19.0	0.1	1.3	21.9
17	104.5	2.5	106.9	1.2	105.7	0.1	8.6	98.3
35	0.1	0.0	0.1	0.0	0.1	0.1	0.0	0.1
42	57.1	0.0	57.1	0.0	57.1	0.1	6.9	50.3
45	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0
46	7.0	0.0	7.0	0.0	7.0	0.3	2.1	4.9
47	4,250.0	803.5	5053.5	401.7	4651.7	0.1	428.7	4624.8
50	51.4	3.5	54.9	1.8	53.1	0.6	30.9	24.0
52	-	0.0	0.0	0.0	0.0	1.0	0.0	0.0
Sub Total	7,257.1	927.3	8,184.3	463.6	7,720.7		690.0	7,494.3
					Not included in RR		(7.8)	***
					Total CCA for RR		682.2	

Notes:

** The Eligible Capital Expenditures ("ECE") transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027.

*** This is the CCA for items such as CCRA True ups and Project Cancellation Costs. As these items are not included in rates, the tax benefits associated should also be excluded from rates.

Witness: Selma Yam

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost Allowance (CCA)
2021 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,803.4	29.3	1832.7	14.7	1818.0	0.0	73.8	1758.9
2	393.1	0.0	393.1	0.0	393.1	0.1	23.6	369.5
3	195.8	0.0	195.8	0.0	195.8	0.1	9.8	186.0
6	49.5	0.0	49.5	0.0	49.5	0.1	4.9	44.5
7	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0
8	158.7	123.7	282.4	61.8	220.6	0.2	66.9	215.5
9	0.2	0.0	0.2	0.0	0.2	0.3	0.1	0.2
10	28.7	10.9	39.5	5.4	34.1	0.3	13.2	26.3
12	1.3	30.3	31.6	15.2	16.5	1.0	30.4	1.2
13	5.7	(0.7)	5.0	(0.3)	5.3	0.0	0.5	4.5
14.1 (ECE)**	33.7	0.0	33.7	0.0	33.7	0.1	2.4	31.4
14.1 (Post-2017)	21.9	11.2	33.1	5.6	27.5	0.1	1.9	31.2
17	98.3	2.0	100.3	1.0	99.3	0.1	8.1	92.2
35	0.1	0.0	0.1	0.0	0.1	0.1	0.0	0.1
42	50.3	0.0	50.3	0.0	50.3	0.1	6.0	44.3
45	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0
46	4.9	0.0	4.9	0.0	4.9	0.3	1.5	3.4
47	4,624.8	968.3	5593.0	484.1	5108.9	0.1	480.0	5113.1
50	24.0	7.8	31.8	3.9	27.9	0.6	19.3	12.5
52	-	0.0	0.0	0.0	0.0	1.0	0.0	0.0
	7,494.3	1,182.8	8,677.1	591.4	8,085.7		742.3	7,934.8
					Not included in RR		(7.1)	***
					Total CCA for RR		735.2	

Notes:
** The Eligible Capital Expenditures ("ECE") transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027.

*** This is the CCA for items such as CCRA True ups and Project Cancellation Costs. As these items are not included in rates, the tax benefits associated should also be excluded from rates.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost Allowance (CCA)
2022 Networks Allocation to Transmission
Year Ending December 31
($ Millions)

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,758.9	22.8	1781.7	11.4	1770.3	0.0	71.7	1709.9
2	369.5	0.0	369.5	0.0	369.5	0.1	22.2	347.4
3	186.0	0.0	186.0	0.0	186.0	0.1	9.3	176.7
6	44.5	0.0	44.5	0.0	44.5	0.1	4.5	40.1
7	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0
8	215.5	78.5	294.0	39.2	254.8	0.2	66.6	227.4
9	0.2	0.0	0.2	0.0	0.2	0.3	0.0	0.1
10	26.3	10.7	37.0	5.4	31.7	0.3	12.7	24.3
12	1.2	15.3	16.5	7.7	8.9	1.0	16.5	0.0
13	4.5	(0.4)	4.1	(0.2)	4.3	0.0	(0.1)	4.2
14.1 (ECE)**	31.4	0.0	31.4	0.0	31.4	0.1	2.2	29.2
14.1 (Post-2017)	31.2	10.8	42.1	5.4	36.7	0.1	2.4	39.7
17	92.2	1.9	94.0	0.9	93.1	0.1	7.6	86.4
35	0.1	0.0	0.1	0.0	0.1	0.1	0.0	0.1
42	44.3	0.0	44.3	0.0	44.3	0.1	5.3	38.9
45	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0
46	3.4	0.0	3.4	0.0	3.4	0.3	1.0	2.4
47	5,113.1	1033.9	6147.0	517.0	5630.0	0.1	533.1	5613.9
50	12.5	2.4	14.9	1.2	13.7	0.6	8.9	6.0
52	-	0.0	0.0	0.0	0.0	1.0	0.0	0.0
	7,934.8	1,175.9	9,110.7	588.0	8,522.8		763.9	8,346.8
					Not included in RR		(6.5) ***	
					Total CCA for RR		757.4	

Notes:

** The Eligible Capital Expenditures ("ECE") transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027.

*** This is the CCA for items such as CCRA True ups and Project Cancellation Costs. As these items are not included in rates, the tax benefits associated should also be excluded from rates.

Witness: Selma Yam

OEB INTERROGATORY #209

Reference:
F-07-02-02A

Interrogatory:
At the above reference, Hydro One provides a reconciliation of its accounting to tax additions for the period 2020-2022

a) Please explain the nature of the line item "asset removal" and why it is part of this reconciliation.

Response:
a) Asset removal costs are expensed for accounting purposes. Unlike accounting, any asset removal costs that relate to the replacement of assets (thereby extending the life of an asset) are required to be capitalized for tax purposes and are eventually depreciated via the capital cost allowance.

OEB INTERROGATORY #210

Reference:
F-07-01

Interrogatory:
Within the regulatory tax evidence that is filed for this proceeding, Hydro One has not provided any details related to its recently filed 2018 corporate tax return.

a) Please provide Schedules 1, 4, 8 and 13 from the 2018 corporate tax return.

Response:
a) Please see attachment 1 to this Exhibit for a copy of the Hydro One Networks Inc. 2018 corporate tax return, which was filed June 26, 2019.

Witness: Nancy Tran

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 **Do not use this area**

Filed: 2019-08-02
EB-2019-0082
Exhibit I-1-OEB-210
Attachment 1
Page 1 of 291

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) 001 87086 5821 RC0001

Corporation's name
002 HYDRO ONE NETWORKS INC.

Address of head office
Has this address changed since the last time we were notified? . . . . 010 1 Yes [ ] 2 No [X]
If **yes**, complete lines 011 to 018.
011 483 BAY STREET, 8TH FLOOR
012 SOUTH TOWER
City: 015 TORONTO
Province, territory, or state: 016 ON
Country (other than Canada): 017 CA
Postal or ZIP code: 018 M5G 2P5

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 1 Yes [ ] 2 No [X]
If **yes**, complete lines 021 to 028.
021 c/o TAX DEPARTMENT
022 483 BAY STREET, 7TH FLOOR
023 SOUTH TOWER
City: 025 TORONTO
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal or ZIP code: 028 M5G 2P5

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? . . . . 030 1 Yes [ ] 2 No [X]
If **yes**, complete lines 031 to 038.
031 483 BAY STREET, 7TH FLOOR
032 SOUTH TOWER
City: 035 TORONTO
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal or ZIP code: 038 M5G 2P5

040 **Type of corporation at the end of the tax year** (tick one)
- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [X] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . 043 Year Month Day

To which tax year does this return apply?
Tax year start (Year Month Day): 060 2018-01-01
Tax year-end (Year Month Day): 061 2018-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes [X] 2 No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 3 Exempt under paragraph 149(1)(t)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area
095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162	X	11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163	X	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170	X	29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II – Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	X	54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI		300	28,604,965	A
Deduct:				
Charitable donations from Schedule 2	311	1,947,631		
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		1,947,631 ▶	1,947,631	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			26,657,334	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C **plus** amount D)		360	26,657,334	
Income exempt under paragraph 149(1)(t)		370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			26,657,334	Z
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . . **410** ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** *** ______ D = ... ______ E1
11,250

Amount C / 500,000 x 5 x [Adjusted aggregate investment income**** ______ – 50,000] = ______ E2

Business limit reduction (amounts E1 or E2, whichever is greater)**** . . . . . ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** ______ F

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . ______ G

Amount F **minus** amount G . . . . . **427** ______ H

Small business deduction

Amount A, B, C, or H, whichever is the least ______ x Number of days in the tax year before January 1, 2018 ______ / Number of days in the tax year 365 x 17.5 % = ______ 1

Amount A, B, C, or H, whichever is the least ______ x Number of days in the tax year after December 31, 2017, and before January 1, 2019 365 / Number of days in the tax year 365 x 18 % = ______ 2

Amount A, B, C, or H, whichever is the least ______ x Number of days in the tax year after December 31, 2018 ______ / Number of days in the tax year 365 x 19 % = ______ 3

Total of amounts 1, 2 and 3 (enter amount I at amount J on page 8) **430** ______ I

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** **For tax years starting after 2018**, the business limit reduction under subparagraph 125(5.1) ITA is the greater of the following amounts:
1) Amount E1, based on the taxable capital employed in Canada for the corporation and associated corporations in the last tax year ending in the preceding calendar year; and,
2) Amount E2, based on the total adjusted aggregate investment income for the corporation and associated corporations in tax years ending in the preceding calendar year.

For more information, consult the Help (F1).

Specified corporate income and assignment under subsection 125(3.2)

Applicable to tax years that begin after March 21, 2016

Except that, if the tax year of your corporation started before **and** ends on or after March 22, 2016 and in the tax year of a CCPC, you can make an assignment of business limit to that other CCPC if its tax year started after March 21, 2016.

	J1 Name of corporation receiving the income and assigned amount	J Business number of the corporation receiving the assigned amount 490	K Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column J [3] 500	L Business limit assigned to corporation identified in column J [4] 505
1.				
			Total 510	Total 515

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
(A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
(B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
(I) persons (other than the private corporation) with which the corporation deals at arm's length, or
(II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column K in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)				A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		B		
Amount 13K from Part 13 of Schedule 27		C		
Personal services business income 432		D		
Amount used to calculate the credit union deduction (amount 2E from Schedule 17)		E		
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6*		G		
Subtotal (**add** amounts B to G)		►		H
Amount A **minus** amount H (if negative, enter "0")				I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %				J

Enter amount J on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			26,657,334	K
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		L		
Amount 13K from Part 13 of Schedule 27		M		
Personal services business income 434		N		
Amount used to calculate the credit union deduction (amount 2E from Schedule 17)		O		
Subtotal (**add** amounts L to O)		►		P
Amount K **minus** amount P (if negative, enter "0")			26,657,334	Q
General tax reduction – Amount Q **multiplied** by 13 %			3,465,453	R

Enter amount R on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ____ x 30 2 / 3 % = ____ A

Foreign non-business income tax credit from line 632 on page 8 . . . . ____ B

Deduct:

Foreign investment income from Schedule 7 . . . . **445** ____ x 8 % = ____ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") ____ ▶ ____ D

Amount A **minus** amount D (if negative, enter "0") . . . . ____ E

Taxable income from line 360 on page 3 . . . . ____ F

Deduct:

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . . ____ G

Foreign non-business income tax credit from line 632 on page 8 . . . . ____ x 75 / 29 = ____ H

Foreign business income tax credit from line 636 on page 8 . . ____ x 4 = ____ I

Subtotal (total of amounts G, H and I) ____ ▶ ____ J

Subtotal (amount F **minus** amount J) (if negative, enter "0") ____ K x 30 2 / 3 % = ____ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . ____ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ____ N

Refundable dividend tax on hand

Eligible refundable dividend tax on hand account (ERDTOH)* (applicable to taxation years that start after 2018)

Eligible refundable dividend tax on hand at the end of the previous tax year . . . . ____ a

Dividend refund from the ERDTOH for the previous tax year . . . . ____ b

Subtotal (amount a **minus** amount b) ____ ▶ ____ O1

Part IV tax payable attributable to eligible dividends received from unconnected corporations (amount N1 from Schedule 3) . . . . ____ c

Part IV tax attributable to taxable dividends received from connected corporations which generated a dividend refund from their ERDTOH account (amount N2 from Schedule 3) . . . . ____ d

Net eligible refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . ____ e

Subtotal (**add** amounts c, d and e) ____ ▶ ____ R1

Eligible refundable dividend tax on hand at the end of the tax year (amount O1 **plus** amount R1) . . . . ____ R2

Refundable dividend tax on hand (continued)

Refundable dividend tax on hand
(for tax years that start after 2018, non-eligible refundable dividend tax on hand account (NERDTOH)*)

Refundable dividend tax on hand at the end of the previous tax year (for tax years that start after 2018, non-eligible refundable dividend tax on hand at the end of the previous tax year)	460			
Dividend refund for the previous tax year (for tax years that start after 2018, dividend refund from the NERDTOH for the previous tax year)	465			
Subtotal (line 460 **minus** line 465)			▶	O2
Refundable portion of Part I tax from line 450 above			P	
Total Part IV tax payable from line 360 in Schedule 3 (for tax years that start after 2018, total Part IV tax payable less the Part IV tax attributable to the ERDTOH account (amount N3 from Schedule 3) (if negative, enter « 0 »))			Q	
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation (for tax years that start after 2018, net non-eligible refundable dividend tax on hand transferred)	480			
Subtotal (**add** amounts P, Q and line 480)			▶	R3
Refundable dividend tax on hand at the end of the tax year (amount O2 **plus** amount R3) (for tax years that start after 2018, non-eligible refundable dividend tax on hand at the end of the tax year)				R4
Refundable dividend tax on hand at the end of the tax year (amount R2 **plus** amount R4)			485	

* For more information, consult the Help (F1).

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year
Refund attributable to eligible dividends paid in the taxation year* (applicable to taxation years that start after 2018)

Eligible Dividend paid in the tax year		x 38 1/3 % =		S1	
Eligible refundable dividend tax on hand at the end of the tax year (amount R2)				T1	
Dividend refund attributable to the ERDTOH (amount S1 or T1, whichever is less)				▶	U1

Dividend refund
(for tax years that start after 2018, dividend refund attributable to non-eligible dividends paid in the tax year*)

Taxable dividends paid in the tax year from line 460 of Schedule 3 (for tax years that start after 2018, taxable non-eligible dividends paid in the tax year)	500,000	x 38 1/3 % =	191,667	S2	
Refundable dividend tax on hand at the end of the tax year (amount R4) (for tax years that start after 2018, non-eligible refundable dividend tax on hand at the end of the tax year)				T2	
Dividend refund (amount S2 or T2, whichever is less) (for tax years that start after 2018, dividend refund attributable to the NERDTOH)				▶	U2

For tax years that start after 2018:

Amount S2 **minus** amount T2 (if negative, enter "0")		S3	
Eligible refundable dividend tax on hand minus dividend refund attributable to the ERDTOH (amount T1 **minus** amount U1)		T3	
Additional dividend refund attributable to the ERDTOH (amount S3 or T3, whichever is less)		▶	U3
Dividend refund (amount U1 **plus** amount U2 **plus** amount U3)			U

Enter amount U on line 784 on page 9.

* For more information, consult the Help (F1).

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %	550	10,129,787	A
Additional tax on personal services business income (section 123.5)			
Taxable income from a personal services business 555 ______ x 5 % =	560		B
Recapture of investment tax credit from Schedule 31	602		C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			D
Taxable income from line 360 on page 3		E	
Deduct: Amount from line 400, 405, 410, or 427 on page 4, whichever is the least		F	
Net amount (amount E **minus** amount F)		▶	G

Refundable tax on CCPC's investment income – 10 2 / 3 % of whichever is less: amount D or amount G	604		H
Subtotal (**add** amounts A, B, C, and H)		10,129,787	I

Deduct:

Small business deduction from line 430 on page 4			J		
Federal tax abatement	608	2,665,733			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount J on page 5	638				
General tax reduction from amount R on page 5	639	3,465,453			
Federal logging tax credit from Schedule 21	640				
Eligible Canadian bank deduction under section 125.21	641				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652	3,997,633			
Subtotal		10,128,819	▶	10,128,819	K

Part I tax payable – Amount I **minus** amount K	968	L

Enter amount L on line 700 on page 9.

Privacy statement

Personal information is collected under the Income Tax Act to administer tax, benefits, and related programs. It may also be used for any purpose related to the enforcement of the Act such as audit, compliance and collections activities. It may be shared or verified with other federal, provincial, territorial or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the Privacy Act, individuals have the right to access their personal information, request correction, or file a complaint to the Privacy Commissioner of Canada regarding the handling of the individual's personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at **canada.ca/cra-info-source**.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	968
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		968

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	19,042,743	
Total tax payable	770	19,043,711	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount U on page 7	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	20,916,170
Total credits	890	20,916,170

20,916,170 B

Refund code **894** 2 Overpayment 1,872,459

Balance (amount A **minus** amount B) -1,872,459

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information **910** ____ Branch number

914 ____ Institution number **918** ____ Account number

If the result is positive, you have a **balance unpaid**. If the result is negative, you have an **overpayment**. Enter the amount on whichever line applies. Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . . ____

For information on how to make your payment, go to **canada.ca/payments**.

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . **896** 1 Yes ☐ 2 No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . **920** ____

Certification

I, **950** Tran (Last name) **951** Nancy (First name) **954** VP, Corporate Tax (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2019-06-26 Date (yyyy/mm/dd) ____ Signature of the authorized signing officer of the corporation **956** (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . **957** 1 Yes X 2 No ☐

958 ____ Name of other authorized person **959** ____ Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. **990** 1

Schedule of Instalment Remittances

Name of corporation contact: Nancy Tran
Telephone number: (416) 345-6778

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	20,916,170

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 20,916,170 **A**

Total instalments credited to the taxation year per T9 20,916,170 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	1,064,000,000	1,058,000,000
	Total tangible capital assets	2008	+	30,543,000,000	29,374,000,000
	Total accumulated amortization of tangible capital assets	2009	–	10,708,000,000	10,284,000,000
	Total intangible capital assets	2178	+	1,020,000,000	910,000,000
	Total accumulated amortization of intangible capital assets	2179	–	445,000,000	374,000,000
	Total long-term assets	2589	+	2,242,000,000	2,882,000,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	23,716,000,000	23,566,000,000
	Liabilities				
	Total current liabilities	3139	+	3,148,000,000	3,357,598,696
	Total long-term liabilities	3450	+	11,357,597,991	10,396,000,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	14,505,597,991	13,753,598,696
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	9,210,402,009	9,812,401,304
	Total liabilities and shareholder equity	3640	=	23,716,000,000	23,566,000,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	5,069,402,009	5,128,401,304

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	5,988,000,000	5,829,000,000
	Cost of sales	8518	–	2,900,000,000	2,875,000,000
	Gross profit/loss	8519	=	3,088,000,000	2,954,000,000
	Cost of sales	8518	+	2,900,000,000	2,875,000,000
	Total operating expenses	9367	+	2,214,580,505	2,137,198,543
	Total expenses (mandatory field)	9368	=	5,114,580,505	5,012,198,543
	Total revenue (mandatory field)	8299	+	5,988,000,000	5,829,000,000
	Total expenses (mandatory field)	9368	–	5,114,580,505	5,012,198,543
	Net non-farming income	9369	=	873,419,495	816,801,457
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	873,419,495	816,801,457
	Total other comprehensive income	9998	=	228,856	303,906
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	18,000,338	22,551,447
	Future (deferred) income tax provision	9995	–	912,918,452	95,769,163
	Total – Other comprehensive income	9998	+	228,856	303,906
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	-57,270,439	698,784,753

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . **095** Yes [X] No [ ]

Is the accountant connected* with the corporation? . . . **097** Yes [X] No [ ]

Note
If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . 1 [ ]

Completed a review engagement report . . . 2 [ ]

Conducted a compilation engagement . . . 3 [ ]

Part 3 – Reservations

If you selected option 1 or 2 under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** Yes [ ] No [ ]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 [ ]

Were notes to the financial statements prepared? . . . **101** Yes [X] No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . **104** Yes [X] No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . **105** Yes [X] No [ ]

Is contingent liability information mentioned in the notes? . . . **106** Yes [X] No [ ]

Is information regarding commitments mentioned in the notes? . . . **107** Yes [X] No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . **108** Yes [X] No [ ]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** Yes [X] No [ ]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	-228,856
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** Yes [ ] No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes [X] No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes [ ] No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** Yes [ ] No [X]

If **yes**, you have to maintain a separate reconciliation.

T2 BAR CODE RETURN

Name: HYDRO ONE NETWORKS INC.

BN: 87086 5821 RC 0001
Tax Year Start: 2018-01-01
Tax Year End: 2018-12-31

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and is wholly-owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the Business Corporations Act (Ontario) and is a wholly -owned subsidiary of Hydro One. The Company owns and operates regulated transmission and distribution businesses. The regulated transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents almost all of the licensed transmission capacity in Ontario. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Rate Setting

OEB March 7, 2019 Decisions

Subsequent to year end, on March 7, 2019, the OEB issued a decision on its reconsideration of its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements dated September 28, 2017 (Original Decision) with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the Electricity Act (Ontario) to tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange.

The March 7, 2019 OEB decision has been determined to be a Type I subsequent event under United States (US) Generally Accepted Accounting Principles (GAAP). As a result, the financial impact of this OEB decision has been reflected in these financial statements, as more fully discussed in Note 12 - Regulatory Assets and Liabilities.

Transmission

In December 2017, the OEB approved Hydro One Networks' 2018 rates revenue requirement of $1,511 million. See Note 12 - Regulatory Assets and Liabilities for additional information.

Distribution

In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. The requested revenue requirements, updated in June 2018, are $1,514 million for 2018, $1,561 million for 2019, $1,607 million for 2020, $1,681 million for 2021, and $1,722 million for 2022. The OEB decision was received on March 7, 2019. See Note 30(D) - Subsequent Events - OEB Regulatory Decisions.

On November 17, 2017, Hydro One filed with the OEB a request for 2018 interim rates based on 2017 OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim 2018 rates based on 2017 OEB- approved rates with no adjustments.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Unconsolidated Financial Statements (Financial Statements) are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with US GAAP, with the exception that business combinations of entities under common control have been accounted for as of the date of the transfer, such that (1) the Financial Statements were not prepared as though the transfer of entities under common control had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information has not been retrospectively adjusted.

The Financial Statements have been prepared solely for the purpose of filing the Company's income tax return. Since these financial statements have not been prepared for general purposes, some users may require additional information. Consolidated Financial Statements of Hydro One for the year ended December 31, 2018 have been prepared and are publicly available.

Hydro One Networks performed an evaluation of subsequent events through to April xx, 2019, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 30 - Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a Type I subsequent event.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

The Company adopted Accounting Standard Codification (ASC) 606 - Revenue from Contracts with Customers on January 1, 2018 using the retrospective method, without the election of any practical expedients. There was no material impact to the Company's revenue recognition policy as a result of adopting ASC 606, and no adjustments were made to prior period reported financial statements amounts.

Nature of Revenues

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved Uniform Transmission Rates (UTR) and the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTR is based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are recognized as electricity is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Networks. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%.

Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the Reliable Energy and Consumer Protection Act, 2002, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2017 for Hydro One Networks' distribution and transmission businesses, respectively. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate	
	Service Life	Range	Average
Property, plant and equipment:			
Transmission	55 years	1% - 2%	2%
Distribution	47 years	1% - 7%	2%
Communication	15 years	1% - 15%	6%
Administration and service	20 years	1% - 20%	6%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base. At December 31, 2018 and 2017, the entire goodwill balance was attributable to the Distribution Business. Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations. Based on assessment performed as at September 30, 2018, the Company has concluded that goodwill was not impaired at December 31, 2018.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One Networks' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2018 and 2017, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). The Company presents net income and OCI in a single continuous Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 17 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation at December 31, 2018 or 2017.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the Consolidated Statements of Operations and Comprehensive Income.

Defined Benefit Pension

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One

Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. The actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with the Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One Networks records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation. When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company's asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance Date issued Description Effective date Impact

ASC 606 May 2014 - November 2017 ASC 606 Revenue from Contracts with Customers replaced ASC 605 Revenue Recognition. ASC 606 provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

January 1, 2018 On January 1, 2018, the Company adopted ASC 606 using the retrospective method, without the election of any practical expedients.

Upon adoption, there was no material impact to the Company's revenue recognition policy and no adjustments were made to prior period reported financial statements amounts. The Company has included the disclosure requirements of ASC 606 for annual and interim periods in the year of adoption.

ASU 2017-07 March
2017 Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable. January 1, 2018
The Company applied for a regulatory asset to maintain the capitalization of post-employment benefit related costs and as such, there is no material impact upon adoption. See Note 2 - Significant Accounting Policies and Note 12 - Regulatory Assets and Liabilities.

Recently Issued Accounting Guidance Not Yet Adopted
Guidance Date issued Description Effective date Anticipated
impact
2016-02
2018-01
2018-10
2018-11
2018-20
2019-01 February 2016 - March 2019 Lessees are required to recognize
the rights and obligations resulting from operating leases as assets (right to

use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under ASC 842 land easements that exist or expired before the entity's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. ASU 2018-10 amends narrow aspects of ASC 842. ASU 2018-11 provides entities with an additional and option transition method in adopting ASC 842. ASU 2018-11 also permits lessors to elect an optional practical expedient to not separate non-lease components from the associated lease component by underlying asset classes. ASU 2018-20 provides relief to lessors that have lease contracts that either require lessees to pay lessor costs directly to a third party or require lessees to reimburse lessors for costs paid by lessors directly to third parties. ASU 2019-01 provides clarification on three issues: determining the fair value of the underlying assets by lessors that are not manufacturers or dealers, presentation of statement of cash flows for sales-type and direct financing leases and interim transition disclosures relating to Topic 250, Accounting Changes and Error Corrections. January 1, 2019 The Company reviewed its existing leases and other contracts that are within the scope of ASC 842. Apart from the existing leases, no other contracts contained lease arrangements. Upon adoption in the first quarter of 2019, the Company will utilize the modified retrospective transition approach using the effective date of January 1, 2019 as its date of initial application. As a result, comparatives will not be updated. The Company will elect the package of practical expedients and the land easement practical expedient upon adoption. The impact to the Company's financial statements will be the recognition of approximately $24 million of Right-of-Use (ROU) assets and corresponding lease obligations on the Consolidated Balance Sheet. The ROU assets and lease obligations represent the present value of the Company's remaining minimum lease payments for leases with terms greater than 12 months. Discount rates used in calculating the ROU assets and lease obligations correspond to the Company's incremental borrowing rate.

2018-07 June 2018 Expansion in the scope of ASC 718 to include share-based payment transactions for acquiring goods and services from non-employees. Previously, ASC 718 was only applicable to share-based payment transactions for acquiring goods and services from employees. January 1, 2019 No impact upon adoption
2018-13 August 2018 Disclosure requirements on fair value measurements in ASC 820 are modified to improve the effectiveness of disclosures in financial statement notes. January 1, 2020 Under assessment
2018-14 August 2018 Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes. January 1, 2021 Under assessment
2018-15 August 2018 The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The accounting for the service element of a hosting arrangement is not affected by the amendment. January 1, 2020 Under assessment

4. BUSINESS COMBINATIONS

On December 10, 2018, the common shares of 1937672 Ontario Inc. were transferred to Hydro One Networks by Hydro One. The transfer was accounted as a non-monetary transfer, based on 1937672 Ontario Inc.'s carrying values at December 10, 2018. On December 10, 2018, 1937672 Ontario Inc. started dissolution proceedings and, as a result, its net assets were transferred to Hydro One Networks.

The following table summarizes the assets and liabilities that were transferred to Hydro One Networks at December 10, 2018:

(millions of dollars)	
Working capital	5
Property, plant and equipment	1
Regulatory assets	21
Investment in subsidiaries	225
Inter-company demand facility	(3)
Deferred income tax liabilities	(19)
Long -term debt	(229)
	1

5. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 (millions of dollars)	2018	2017
Depreciation of property, plant and equipment	628	613
Amortization of intangible assets	71	62
Amortization of regulatory assets	21	23
Depreciation and amortization	720	698
Asset removal costs	89	90
	809	788

6. FINANCING CHARGES

Year ended December 31 (millions of dollars)	2018	2017
Interest on long-term debt (Note 24)	427	429
Interest on inter-company demand facility (Note 25)	23	

12

Other 20 13

Less: Interest capitalized on construction and development in progress

(53) (56)

417 398

7. INCOME TAXES

As a rate regulated utility company, the Company's effective tax rate excludes temporary differences that are recoverable in future rates charged to customers. Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of dollars) 2018 2017

Income before income taxes 874 816

Income taxes at statutory rate of 26.5% (2017 - 26.5%) 232

216

Increase (decrease) resulting from:

Net temporary differences recoverable in future rates charged to customers:

Capital cost allowance in excess of depreciation and amortization

(64) (50)

Overheads capitalized for accounting but deducted for tax purposes

(19) (17)

Interest capitalized for accounting but deducted for tax purposes

(14) (15)

Pension contributions in excess of pension expense (11)

(13)

Environmental expenditures (6) (6)

Other (6) 1

Net temporary differences (120) (100)

Net permanent differences 2 2

Write-off of unregulated deferred income tax asset (Notes 12, 30) 885

-

Non-recurring tax recovery relating to deferred tax asset sharing1 (Notes 12, 30) (68) -

Total income taxes 931 118

Effective income tax rate 106.5 % 14.5 %

1 This represents the reversal of cumulative deferred tax expenses recorded in 2017 and 2018 relating to temporary differences that are now being allocated to ratepayers. For rate-setting purposes, the deferred income tax expenses or recovery relating to temporary differences that will be included in the rate-setting process are recorded as regulatory assets and liabilities on the balance sheet.

The major components of income tax expense are as follows:

Year ended December 31 (millions of dollars) 2018 2017

Current income taxes 18 22

Deferred income taxes 913 96

Total income taxes 931 118

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities expected to be included in the rate -setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates. Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2018 and 2017, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	2018	2017
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	517	552
Non-capital losses	261	237
Non-depreciable capital property	130	130
Tax credit carryforwards	67	48
Depreciation and amortization in excess of capital cost allowance	49	103
Environmental expenditures	47	58
Regulatory amounts that are not recognized for tax purposes	31	-
Other	27	8
	1,129	1,136
Less: valuation allowance	(151)	(133)
Total deferred income tax assets	978	1,003
Deferred income tax liabilities		
Goodwill	(10)	(10)
Regulatory amounts that are not recognized for tax purposes	-	(34)
Other	(19)	(15)
Total deferred income tax liabilities	(29)	(59)

Net deferred income tax assets	949	944

The net deferred income tax assets are presented on the Balance Sheets as long -term assets.

8. ACCOUNTS RECEIVABLE

December 31 (millions of dollars)	2018	2017
Accounts receivable - billed	282	295
Accounts receivable - unbilled	353	364
Accounts receivable, gross	635	659
Allowance for doubtful accounts	(21)	(29)
Accounts receivable, net	614	630

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2018 and 2017:

Year ended December 31 (millions of dollars)	2018	2017
Allowance for doubtful accounts - beginning	(29)	(35)
Write-offs	25	25
Additions to allowance for doubtful accounts	(17)	(19)
Allowance for doubtful accounts - ending	(21)	(29)

9. OTHER CURRENT ASSETS

December 31 (millions of dollars)	2018	2017
Regulatory assets (Note 12)	29	36
Prepaid expenses and other assets	32	32
Materials and supplies	17	15
	78	83

10. PROPERTY, PLANT AND EQUIPMENT

December 31, 2018 (millions of dollars) Property, Plant

and Equipment1 Accumulated Depreciation Construction

in Progress

Total

Transmission 15,909 5,411 760 11,258

Distribution 10,517 3,538 73 7,052

Communication 1,112 802 33 343

Administration and service 1,537 889 59 707

Easements 543 68 - 475

29,618 10,708 925 19,835

1 Includes future use assets totalling $147 million.

December 31, 2017 (millions of dollars) Property, Plant

and Equipment1 Accumulated Depreciation Construction

in Progress

Total

Transmission 14,854 5,137 988 10,705

Distribution 10,155 3,488 147 6,814

Communication 1,083 741 23 365

Administration and service 1,545 853 45 737

Easements 534 65 - 469

28,171 10,284 1,203 19,090

1 Includes future use assets totalling $154 million.

Financing charges capitalized on property, plant and equipment under

construction were $50 million in 2018 (2017 - $54 million).

11. INTANGIBLE ASSETS

December 31, 2018 (millions of dollars) Intangible

Assets Accumulated Amortization Development

in Progress

Total

Computer applications software 788 440 59 407

Other 5 5 - -

793 445 59 407

December 31, 2017 (millions of dollars) Intangible

Assets Accumulated Amortization Development

in Progress

Total

Computer applications software 696 370 41 367

Other 5 4 - 1

701 374 41 368

Financing charges capitalized to intangible assets under development were $2 million in 2018 (2017 - $3 million). The estimated annual amortization expense for intangible assets is as follows: 2019 - $67 million; 2020 - $50 million; 2021 - $48 million; 2022 - $46 million; and 2023 - $35 million.

12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Networks has recorded the following regulatory assets and liabilities:

December 31 (millions of dollars) 2018 2017

Regulatory assets:

Deferred income tax regulatory asset 852 1,689

Environmental 130 161

Stock-based compensation 42 40

Post-retirement and post-employment benefits non-service cost 39

-

Distribution system code exemption 10 10

Post-retirement and post-employment benefits - 36

Foregone revenue deferral - 22

Other 23 15

Total regulatory assets 1,096 1,973

Less: current portion (29) (36)

1,067 1,937

Regulatory liabilities:

Post-retirement and post-employment benefits 129 -

Deferred income tax regulatory liability 80 -

Pension cost differential 55 23

Green Energy expenditure variance 52 60

Retail settlement variance account 39 -

External revenue variance 26 46

2015-2017 rate rider 6 6

PST savings deferral 4 4

Conservation and Demand Management (CDM) deferral variance -

28

Other 17 13

Total regulatory liabilities 408 180

Less: current portion	(89)	(57)
	319	123

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2018 income tax expense would have been lower by approximately $689 million (2017 - higher by $119 million).

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the Electricity Act (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One Limited shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a decision and order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of a portion of Hydro One Networks' transmission deferred income tax regulatory asset. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, it would also result in an additional impairment of a portion of Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Divisional Court of Ontario (Appeal). In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Decision relating to the deferred tax asset to an OEB panel for reconsideration.

Subsequent to year end, on March 7, 2019, the OEB issued its reconsideration decision and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019 the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. As a result of this subsequent event that requires adjustment in the 2018 financial statements, the Company has recognized a reduction in Hydro One Networks' distribution deferred income tax regulatory asset of $473 million and Hydro One Networks' transmission deferred income tax regulatory asset of $558 million, an increase in deferred income tax regulatory liability of $80 million, and a decrease in the foregone revenue deferral regulatory asset of $22 million. After recognition of the related $300 million deferred tax asset, the Company has recorded an $833 million one-time decrease in net income as a reversal of revenues of $22 million, and charge to deferred tax expense of $811 million. Notwithstanding the recognition of the effects of the decision in the financial statements, the Company is currently considering its options under the Appeal.

Environmental

Hydro One Networks records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. The Company has recorded an equivalent amount as a regulatory asset. In 2018, the environmental regulatory asset decreased by $16 million (2017 - $3 million) to reflect related changes in the Company's PCB and LAR environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One Networks' actual environmental expenditures. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been lower by $16 million (2017 - $3 million). In addition, 2018 amortization expense would have been lower by $21 million (2017 - $23 million), and 2018 financing charges would have been higher by $6 million (2017 - $7 million).

Post-Retirement and Post-Employment Benefits - Non-Service Cost

Hydro One applied to the OEB for a regulatory asset to record the components other than service costs relating to its post-retirement and post-employment benefits that would have previously been capitalized to property, plant and equipment and intangible assets prior to adoption of ASU 2017-07. In May 2018 and March 2019, the OEB approved the regulatory asset for Hydro One Networks' Transmission Business and Distribution Business, respectively. Hydro One Networks has recorded the components other than service costs relating to its post-retirement and post-employment benefits that would have been capitalized to property, plant and equipment and intangible assets, in the Post-Retirement and Post-Employment Benefits Non-Service Cost Regulatory Asset.

Stock-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been higher by $1 million (2017 - $7 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory liability, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2018 OCI would have been higher by $166 million (2017 - $205 million).

Pension Cost Differential

A pension cost differential account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost differential account as at December 31, 2015, including accrued interest, which was recovered over a two-year period ended December 31, 2018. The distribution business portion of the balance as at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application. In the absence of rate-regulated accounting, 2018 revenue would have been higher by $29 million (2017 - $24 million).

Distribution System Code (DSC) Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the DSC, with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Networks distribution applications. In 2015, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2018 or 2017. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented.

Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

Retail Settlement Variance Account (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The balance as at December 31, 2014, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which was returned to customers over a two-year period ended December 31, 2018. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' distribution rate application for 2015-2019, the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015 -2017 Rate Rider account included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32- month period ended December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application and has not been requested in the current distribution rate application.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administration expenses or capital expenditures for past revenue requirements approved during a full cost-of-service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administration expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable, and calculations for tracking and refund were requested by the OEB. For Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2015 and recorded in a deferral account, as directed by the OEB. In March 2015, the OEB approved the disposition of the PST Savings Deferral account at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual CDM and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account related to the actual 2013 and 2014 CDM and demand response results on load forecasts, which are inputs in the UTR, compared to the amounts included in 2013 and 2014 revenue requirements, respectively. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and returned to customers over a 2-year period ended December 31, 2018.

13. INVESTMENT IN SUBSIDIARY

In 2018, 1937672 Ontario Inc., the parent company of Hydro One Sault Ste Marie entities, was transferred to Hydro One Networks by Hydro One. This resulted in a transfer of the $225 million investment in 1937672 Ontario Inc. to Hydro One Networks, thereby increasing Hydro One's investment in Hydro One Networks by

$225 million. See Note 4 - Business Combinations for additional information.

14. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 (millions of dollars)	2018	2017
Accrued liabilities	537	544
Accounts payable	163	165
Accrued interest (Note 25)	95	98
Regulatory liabilities (Note 12)	89	57
	884	864

15. OTHER LONG-TERM LIABILITIES

December 31 (millions of dollars)	2018	2017
Post-retirement and post-employment benefit liability (Note 19)	1,383	1,484
Environmental liabilities (Note 20)	110	135
Long-term inter-company payable (Note 25)	34	36
Long-term accounts payable and other liabilities	17	25
Asset retirement obligations (Note 21)	10	8
	1,554	1,688

16. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt. In addition, at December 31, 2018, the long-term debt includes debt of $229 million transfered to Hydro One Networks from Hydro One (see Note 4 - Business Combinations). The following table presents long-term debt outstanding at December 31, 2018 and 2017:

December 31 (millions of dollars)	2018	2017
Long-term debt	10,246	9,367
Add: Net unamortized debt premiums	13	14
Add: Unrealized mark-to-market gain1	(5)	(9)
Less: Deferred debt issuance costs	(40)	(37)
Less: Long-term debt payable within one year	(728)	(750)
Long-term debt	9,486	8,585

1 The unrealized mark-to-market net gain relates to $30 million of notes due in 2020, $500 million notes due in 2019, and $300 million notes due in 2021. The unrealized mark-to-market net gain is offset by a $5 million (2017 - $9 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

In 2018, Hydro One issued $1,400 million (2017 - $nil) of long-term debt under its MTN Program, all of which was mirrored down to Hydro One Networks.

In 2018, Hydro One repaid $750 million (2017 - $600 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $750 million (2017 - $600 million) to Hydro One.

Principal and Interest Payments

Principal repayments, interest payments, and related weighted-average interest rates are summarized by year in the following table:

	Long-term Debt Principal Repayments	Interest Payments	Weighted Average Interest Rate
Years	(millions of dollars)	(millions of dollars)	(%)
2019	728	431	2.0
2020	330	413	4.2
2021	800	397	2.4

2022	580	379	3.2
2023	-	369	-
	2,438	1,989	2.7
2024-2028	840	1,770	3.1
2029 and thereafter	6,968	4,335	5.1
	10,246	8,094	4.3

17. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Company classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Networks has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest

-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2018 and 2017, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, inter-company demand facility, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2018 and 2017 are as follows:

December 31 (millions of dollars)	2018 Carrying Value	2018 Fair Value	2017 Carrying Value	2017 Fair Value
$500 million notes due 2019	495	495	492	492
$30 million notes due 2020	30	30	29	29
$300 million notes due 2021	300	300	-	-
Other notes and debentures	9,389	10,077	8,814	10,255
Long-term debt, including current portion	10,214	10,902	9,335	10,776

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks.

At December 31, 2018, Hydro One Networks had interest-rate swaps in the amount of $830 million (2017 - $530 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges.

The Company's fair value hedge exposure was approximately 8% (2017 - 6%) of its total long-term debt. At December 31, 2018, Hydro One Networks had the following interest-rate swaps designated as fair value hedges:

o $500 million fixed-to-floating interest-rate swap agreements to convert $500 million notes maturing on November 18, 2019 into three-month variable rate debt;

o a $30 million fixed-to-floating interest-rate swap agreement to convert $30 million of the $350 million notes maturing on April 30, 2020 into three-month variable rate debt; and

o a $300 million fixed-to-floating interest-rate swap agreement to convert $300 million notes maturing on June 25, 2021 into three-month variable rate debt.

At December 31, 2018 and 2017, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2018 and 2017 is as follows:

December 31, 2018 (millions of dollars) Carrying

Value Fair

Value

Level 1

Level 2

Level 3

Assets:

Cash and cash equivalents 124 124 124 -

-

124 124 124 - -

Liabilities:

Inter-company demand facility 1,447 1,447 1,447

- -

Long-term debt, including current portion 10,214 10,902

- 10,902 -

Derivative instruments

Fair value hedges - interest-rate swaps 5 5 -

5 -

11,666 12,354 1,447 10,907 -

December 31, 2017 (millions of dollars) Carrying

Value Fair

Value

Level 1

Level 2

Level 3

Assets:

Cash and cash equivalents 37 37 37 -

-

37 37 37 - -

Liabilities:

Inter-company demand facility 1,526 1,526 1,526

- -

Long-term debt, including current portion 9,335 10,776

- 10,776 -

Derivative instruments

Fair value hedges - interest-rate swaps 9 9 -

9 -

10,870 12,311 1,526 10,785 -

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2018 or 2017.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived

using a formulaic approach that takes anticipated interest rates into account.
The Company is not currently exposed to material commodity price risk or material foreign exchange risk.
The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.
A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Company's net income for the years ended December 31, 2018 and 2017.
For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2018 and 2017 was not material.
Credit Risk
Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2018 and 2017, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One Networks did not earn a material amount of revenue from any single customer. At December 31, 2018 and 2017, there was no material accounts receivable balance due from any single customer.
At December 31, 2018, the Company's provision for bad debts was $21 million

(2017 - $29 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2018, approximately 5% (2017 - 5%) of the Company's net accounts receivable were outstanding for more than 60 days. Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2018 and 2017, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2018, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund normal operating requirements.

18. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. At December 31, 2018 and 2017, the Company's capital structure was as follows:

December 31 (millions of dollars)	2018	2017
Long-term debt payable within one year	728	750
Inter-company demand facility	1,447	1,526
Less: cash and cash equivalents	(124)	(37)
	2,051	2,239
Long-term debt	9,486	8,585
Common shares	4,144	4,687
Retained earnings	5,068	5,127
Contributed surplus	5	5
Total capital	20,754	20,643

19. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a DC Plan, a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the Income Tax Act (Canada) in the form of credits to a notional account.

Hydro One Networks contributions to the DC Plan for the year ended December 31, 2018 were $1 million (2017 - $1 million).

Pension Plan and Supplemental Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. Annual Pension Plan contributions for 2018 were $75 million (2017 - $87 million). Estimated annual Pension Plan contributions for the years 2019, 2020, 2021, 2022, 2023 and 2024 are approximately $78 million, $77 million, $78 million, $79 million, $81 million and $83 million, respectively. The most recent actuarial valuation was performed effective December 31, 2017, and the next actuarial valuation will be performed no later than effective December 31, 2020. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the Income Tax Act (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

At December 31, 2018, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,752 million (2017 - $8,258 million). The fair value of pension plan assets available for these benefits was $7,205 million (2017 - $7,277 million).

Post-Retirement and Post-Employment Plans

During the year ended December 31, 2018, the Company charged $49 million (2017 - $55 million) of post-retirement and post-employment benefit costs to operation, and capitalized $66 million (2017 - $70 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2018 were $48 million (2017 - $42 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $166 million (2017 - $205 million).

The Company presents its post-retirement and post-employment benefit liabilities on its Balance Sheets as follows:

December 31 (millions of dollars)	2018	2017
Accrued liabilities	53	51
Post-retirement and post-employment benefit liability	1,383	1,484
Net unfunded status	1,436	1,535

20. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2018 and 2017:

Year ended December 31, 2018 (millions of dollars)	PCB	LAR	Total
Environmental liabilities - beginning	134	27	161

Interest accretion 5 1 6

Expenditures (16) (5) (21)

Revaluation adjustment (15) (1) (16)

Environmental liabilities - ending 108 22 130

Less: current portion (15) (5) (20)

93 17 110

Year ended December 31, 2017 (millions of dollars) PCB LAR Total

Environmental liabilities - beginning 143 37 180

Interest accretion 6 1 7

Expenditures (16) (7) (23)

Revaluation adjustment 1 (4) (3)

Environmental liabilities - ending 134 27 161

Less: current portion (20) (6) (26)

114 21 135

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

December 31, 2018 (millions of dollars) PCB LAR Total

Undiscounted environmental liabilities 118 22 140

Less: discounting environmental liabilities to present value (10)

- (10)

Discounted environmental liabilities 108 22 130

December 31, 2017 (millions of dollars) PCB LAR Total

Undiscounted environmental liabilities 142 28 170

Less: discounting environmental liabilities to present value (8)

(1) (9)

Discounted environmental liabilities 134 27 161

At December 31, 2018, the estimated future environmental expenditures were as follows:

(millions of dollars)

2019 21

2020 27

2021 30

2022 30

2023 27

Thereafter 5

140

Hydro One Networks records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCB

The Environment Canada regulations, enacted under the Canadian Environmental Protection Act, 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB -contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm. The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $118 million (2017 - $142 million). These expenditures are expected to be incurred over the period from 2019 to 2024. As a result of its annual review of environmental liabilities, the

Company recorded a revaluation adjustment in 2018 to decrease the PCB environmental liability by $15 million (2017 - increase by $1 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $22 million (2017 - $28 million). These expenditures are expected to be incurred over the period from 2019 to 2023. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2018 to decrease the LAR environmental liability by $1 million (2017 - $4 million).

21. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled.

Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 4.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, the Company recorded a revaluation adjustment in 2018 to increase the asset retirement liability by $2 million (2017 - $nil).

At December 31, 2018, Hydro One Networks had recorded asset retirement obligations of $10 million (2017 - $8 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

22. SHARE CAPITAL

Common Shares

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2018 and 2017, Hydro One Networks had 207,557,181 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2018, Hydro One Networks declared common share dividends in the amount of $1 million (2017 - $2 million) and made a return of stated capital of $545 million (2017 - $509 million) to Hydro One.

23. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income (loss) attributable to common shareholder of Hydro One Networks by the weighted average number of common shares outstanding. The weighted average number of shares outstanding at December 31, 2018 was 207,557,181 (2017 - 207,557,181). There were no dilutive securities during 2018 or 2017.

24. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (formerly the

Society of Energy Professionals) (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an inter-company agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,913,671 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by Hydro One Networks.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,352,503 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by Hydro One Networks.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks was $108 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2018, 468,131 common shares were issued under the Share Grant Plans (2017 - 365,664) to eligible employees of Hydro One Networks. Total stock-based compensation recognized by Hydro One Networks during 2018 was $12 million (2017 - $16 million) and was recorded as a regulatory asset.

A summary of Hydro One Networks' share grant activity under the Share Grant Plans during years ended December 31, 2018 and 2017 is presented below:

Year ended December 31, 2018 Share Grants
(number of common shares) Weighted-Average
Price

Share grants outstanding - beginning	4,688,096	$20.50
Vested and issued1	(468,131)	-

Forfeited (104,127) $20.50

Share grants outstanding - ending 4,115,838 $20.50

1 In 2018,Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Year ended December 31, 2017 Share Grants

(number of common shares) Weighted-Average

Price

Share grants outstanding - beginning 5,185,957 $20.50

Vested and issued1 (365,664) -

Forfeited (132,197) $20.50

Share grants outstanding - ending 4,688,096 $20.50

1 In 2017, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU Share Grant Plan. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2018 and 2017, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks were as follows:

Year ended December 31 (number of DSUs)	2018	2017
DSUs outstanding - beginning	145,176	91,897
Granted	49,870	53,279
Settled	(134,864)	-
DSUs outstanding - ending	60,182	145,176

For the year ended December 31, 2018, an expense of $1 million (2017 - $1 million) was recognized in earnings with respect to the Directors' DSU Plan.

At December 31, 2018, a liability of $1 million (2017 - $3 million) related to Directors' DSUs has been recorded at the December 31, 2018 closing price of Hydro One Limited common shares of $20.25. This liability is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

DSUs related to the Company's former Board of Directors were settled at the June 29, 2018 (last business day in June 2018) closing price of Hydro One Limited common shares of $20.04, with an amount of approximately $3 million paid in 2018.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One

Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2018 and 2017, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks were as follows:

Year ended December 31 (number of DSUs)	2018	2017
DSUs outstanding - beginning	52,503	-
Granted	22,569	53,571
Paid	-	(1,068)
DSUs outstanding - ending	75,072	52,503

For the year ended December 31, 2018, an expense recognized in earnings with respect to the Management DSU Plan was $nil (2017 - $2 million). At December 31, 2018, a liability of $1 million (2017 - $2 million) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited common shares of $20.25 and is included in long-term accounts payable and other liabilities on the Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum

Company contribution per calendar year. In 2018, Company contributions made under the ESOP were $1 million (2017 - $2 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2018 and 2017, LTIP awards granted by Hydro One Limited that related to Hydro One Networks were as follows:

PSUs

RSUs

Year ended December 31 (number of units)	2018	2017	2018	2017
Units outstanding - beginning	348,416	159,015	315,881	179,477
Granted	254,022	237,529	201,535	194,038
Vested and issued1	(116)	(567)	(98,834)	

(14,037)

Forfeited (30,488) (47,561) (30,057)

(43,597)

Settled (105,854) - (71,281) -

Units outstanding - ending 465,980 348,416 317,244

315,881

1 In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

The grant date total fair value of the awards granted in 2018 was $10 million (2017 - $10 million). The compensation expense related to the PSU and RSU awards recognized by the Company during 2018 was $8 million (2017 - $4 million). The expense recognized in 2018 included $1 million related to previously awarded PSUs and RSUs to Hydro One's former President and CEO for which costs had not previously been recognized. These awards were settled in 2018 through a one-time cash settlement arrangement.

At December 31, 2018, $8 million (2017 - $6 million) payable relating to PSU and RSU awards was included in due to related parties on the Balance Sheets.

Stock Options

Hydro One Limited is authorized to grant stock options under its LTIP to certain eligible employees. During 2018, Hydro One Limited granted 1,450,880 stock options (2017 - nil). The stock options granted are exercisable for a period not to exceed seven years from the date of grant and vest evenly over a three-year period on each anniversary of the date of grant.

The fair value based method is used to measure compensation expense related to stock options and the expense is recognized over the vesting period on a straight-line basis. The fair value of the stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model. Stock options granted and the weighted-average assumptions used in the valuation model for options granted during 2018 are as follows:

Exercise price1	$	20.70
Grant date fair value per option	$	1.66
Valuation assumptions:		
Expected dividend yield2	3.78	%
Expected volatility3	15.01	%
Risk-free interest rate4	2.00	%
Expected option term5	4.5 years	

1 Hydro One Limited common share price on the date of the grant.

2 Based on dividend and Hydro One Limited common share price on the date of the grant.

3 Based on average daily volatility of Hydro One Limited's peer entities for a 4.5-year term.

4 Based on bond yield for an equivalent Canadian government bond.

5 Determined using the option term and the vesting period.

During 2018 and 2017, the activity of stock options granted by Hydro One Limited that related to Hydro One Networks were as follows:

Year ended December 31 (number of stock options)	2018	2017
Stock options outstanding - beginning	-	-
Granted1	671,567	-
Cancelled2	(111,666)	-
Stock options outstanding - ending1	559,901	-

1 All stock options granted and outstanding at December 31, 2018 are non-vested.

2 During 2018, stock options previously awarded to the Company's former President and CEO were cancelled. The Hydro One Networks unrecognized compensation expense related to the cancelled stock options was not significant.

The compensation expense related to stock options recognized by the Company during 2018 was not significant.

25. RELATED PARTY TRANSACTIONS

The Company is indirectly owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2018. The IESO, Ontario Power Generation Inc. (OPG), OEFC, and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Province.

Year ended December 31 (millions of dollars)

Related Party Transaction 2018 2017

IESO Power purchased 1,636 1,583

Transmission services - amounts received1 1,570

1,428

Amounts related to electricity rebates 475 357

Distribution revenues related to rural rate protection 239

247

Funding received related to CDM programs 62 59

OPG Power purchased 10 9

Revenues related to provision of services and supply of electricity

8 7

Costs related to the purchase of services - 1

OEFC Power purchased from power contracts administered by the OEFC

2 2

OEB OEB fees 8 8

Hydro One Limited and its subsidiaries2 Revenues for services provided

9 5

Services received - costs expensed 24 32

Interest expense on long-term debt 427 429

Interest expense on inter-company demand facility 23

12

Return of stated capital 545 509

Dividends 1 2

Stock-based compensation costs 20 20

1 Consistent with the Company's revenue recognition policy, the Company recognized revenues of $1,584 million in 2018 (2017 - $1,489 million).

2 In 2018, Hydro One transferred 1937672 Ontario Inc. to Hydro One Networks. See Note 4 - Business Combinations.

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

The amounts due to and from related parties at December 31, 2018 and 2017 are as follows:

December 31 (millions of dollars)	2018	2017
Inter-company demand facility	(1,447)	(1,526)
Due from related parties	248	245
Due to related parties	(89)	(156)
Accrued interest	(95)	(98)
Long-term inter-company payable	(34)	(36)
Long-term debt, including current portion	(10,214)	(9,336)

26. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of dollars)	2018	2017
Accounts receivable	19	187
Due from related parties	(3)	(78)
Materials and supplies	(2)	1
Other assets	2	3
Accounts payable	(2)	6
Accrued liabilities	(4)	(83)
Due to related parties	(65)	(90)
Accrued interest	(6)	(6)
Long-term accounts payable and other liabilities	(4)	(7)
Post-retirement and post-employment benefit liability	25	86
	(40)	19

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the Statements of Cash Flows for the years ended December 31, 2018 and 2017. The reconciling items include change in accruals and capitalized depreciation.

Year ended December 31, 2018 (millions of dollars)

Property, Plant and Equipment

Intangible Assets

Total

Capital investments (1,431) (121)

(1,552)

Reconciling items 30 1 31

Cash outflow for capital expenditures (1,401)

(120) (1,521)

Year ended December 31, 2017 (millions of dollars)

Property, Plant and Equipment

Intangible Assets

Total

Capital investments (1,466) (73)

(1,539)

Reconciling items 26 (6) 20

Cash outflow for capital expenditures (1,440)

(79) (1,519)

Capital Contributions

Hydro One Networks enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One Networks based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One Networks. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One Networks will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2018, capital contributions from these reassessments totalled $7 million (2017 - $9 million), which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

Supplementary Information

Year ended December 31 (millions of dollars)	2018	2017
Net interest paid	430	436
Income taxes paid	14	11

27. CONTINGENCIES

Legal Proceedings

Hydro One Networks is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Hydro One and certain of its subsidiaries, including Hydro One Networks, are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The action was commenced in the Superior Court of Ontario on September 9, 2015. The plaintiff's motion for certification was dismissed by the court in November 2017. The plaintiff appealed the court's decision to the Divisional Court. The appeal was heard in October 2018; the Divisional Court dismissed the appeal in December 2018; and in January 2019, the plaintiff applied for leave to appeal to the Ontario Court of Appeal. The plaintiff's application for leave to appeal was denied by the Ontario Court of Appeal in March 2019, which means that the lawsuit has effectively ended.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the Indian Act (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2018, the Company paid approximately $2 million (2017 - $2 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

28. COMMITMENTS

The following table presents a summary of Hydro One Networks' commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter:

December 31, 2018 (millions of dollars) Year 1 Year 2 Year 3
Year 4 Year 5 Thereafter

Outsourcing and other agreements 161 104 29 2
3 11

Long-term software/meter agreement 17 16 2 1

2 1

Operating lease commitments	6	10	4	1	1

3

Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services. The agreement expires on February 28, 2021 for information technology services, on October 31, 2021 for supply chain services, and on December 31, 2019 for the remaining back-office services.

On March 1, 2018, Hydro One insourced its customer service operations, which had been previously outsourced to Inergi and Vertex Customer Management (Canada) Limited since 2002.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The agreement with Brookfield for these services expires in December 2024, with an option for the Company to renew the agreement for an additional term of three years.

Long-term Software/Meter Agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

Operating Leases

Hydro One Networks is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One Networks by entering into these leases. During the year ended December 31, 2018, the Company made lease payments totalling $10 million (2017 - $10 million).

Other Commitments

The following table presents a summary of Hydro One Networks' other commercial commitments by year of expiry in the next 5 years and thereafter:

December 31, 2018 (millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Letters of credit1	169	-	-	-	-	-
Guarantees2	325	-	-	-	-	-

1 Letters of credit consist of letters of credit totalling $155 million related to retirement compensation arrangements, a $13 million letter of credit provided to the IESO for prudential support, and $1 million in letters of credit to satisfy debt service reserve requirements.

2 Guarantees consist of prudential support provided to the IESO by Hydro One on behalf of the Company.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees and/or letters of credit if these purchasers fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for Hydro One's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit.

29. SEGMENTED REPORTING

Hydro One Networks has three reportable segments:

o The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;

o The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and

o Other Segment, which includes the Company's non-rate-regulated activities, such as donations, and deferred income tax assets related to IPO.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Year ended December 31, 2018 (millions of dollars) Transmission

Distribution Other Unconsolidated

Revenues 1,622 4,363 3 5,988

Purchased power - 2,900 - 2,900

Operation, maintenance and administration 418 562 8

988

Depreciation and amortization 419 390 - 809

Income (loss) before financing charges and income taxes 785 511

(5) 1,291

Capital investments 979 573 - 1,552

Year ended December 31, 2017 (millions of dollars) Transmission

Distribution Other Unconsolidated

Revenues 1,514 4,306 9 5,829

Purchased power - 2,875 - 2,875

Operation, maintenance and administration 382 558 13

953

Depreciation and amortization 403 384 - 787

Income (loss) before financing charges and income taxes 729 489

(4) 1,214

Capital investments 954 585 - 1,539

Total Assets by Segment:

December 31 (millions of dollars) 2018 2017

Transmission 12,967 12,164

Distribution 8,836 8,606

Other 1,913 2,733

Total assets 23,716 23,503

All revenues, assets and costs, as the case may be, are earned, held or incurred in Canada.

30. SUBSEQUENT EVENTS

(A) Dividends and Return of Stated Capital

On February 20, 2019, Hydro One Networks declared common share dividends of $1 million, and a return of stated capital of $138 million was approved.

(B) Stock-based Compensation

Subsequent to December 31, 2018, Hydro One Limited issued from treasury 72,722 and 450,622 common shares to eligible Transmission Business employees in accordance with provisions of the LTIP and Share Grant Plans, respectively.

(C) Lake Superior Link Project

On February 15, 2018, Hydro One filed an application with the OEB to construct a transmission line (East-West Tie Line) in northwestern Ontario (Lake Superior Link Project). During 2018, the Company capitalized costs totaling approximately $11 million associated with this project. On February 11, 2019, the OEB awarded the project to a competitor, as directed by the Province on January 30, 2019. As a result, in the first quarter of 2019, Hydro One recognized an impairment loss of approximately $11 million associated with previously capitalized costs related to this project.

(D) OEB Regulatory Decisions

Deferred Income Tax Regulatory Asset

Subsequent to year end, on March 7, 2019, the OEB issued a decision on its reconsideration of its Original Decision with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the Electricity Act (Ontario) to tax payments under the federal and provincial tax regime. The OEB's Original Decision concluded that these benefits should not accrue entirely to Hydro One shareholders and that a portion should be shared with ratepayers. The OEB has concluded that the Original Decision was reasonable and should be upheld. The March 7, 2019 OEB decision has been determined to be a Type I subsequent event under US GAAP. As a result, the financial impact of this OEB decision has been reflected in these financial statements, as more fully discussed in Note 12 - Regulatory Assets and Liabilities.

Hydro One Networks' 2018-2022 Distribution Rates

Also, on March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. This aspect of the decision has been reflected in the adjustments discussed in Note 12 - Regulatory Assets and Liabilities. The other impacts from the OEB decision for Hydro One Networks' 2018-2022 distribution rates will be reflected prospectively in 2019.

(E) Long-term Debt

On April 5, 2019, Hydro One issued the following long-term debt under its MTN Program:

o $700 million notes with a maturity date of April 5, 2024 and a coupon rate of 2.54%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 2.79%;

o $550 million notes with a maturity date of April 5, 2029 and a coupon rate of 3.02%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 3.27%; and

o $250 million notes with a maturity date of April 5, 2050 and a coupon rate of 3.64%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 3.89%.

On March 21, 2019, Hydro One repaid $228 million of maturing long-term debt notes under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $228 million to Hydro One.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

Assets – lines 1000 to 2599

1000	124,000,000	1060	635,000,000	1061	-21,000,000
1120	17,000,000	1400	248,000,000	1480	61,000,000
1599	1,064,000,000	1900	29,618,000,000	1901	-10,708,000,000
1920	925,000,000	2008	30,543,000,000	2009	-10,708,000,000
2010	852,000,000	2011	-445,000,000	2012	168,000,000
2178	1,020,000,000	2179	-445,000,000	2240	225,000,000
2420	1,068,000,000	2421	949,000,000	2589	2,242,000,000
2599	23,716,000,000				

Liabilities – lines 2600 to 3499

2620	884,000,000	2700	728,000,000	2860	1,536,000,000
3139	3,148,000,000	3140	9,486,000,000	3320	1,871,597,991
3450	11,357,597,991	3499	14,505,597,991		

Shareholder equity – lines 3500 to 3640

3500	4,144,000,000	3541	5,000,000	3580	-8,000,000
3600	5,069,402,009	3620	9,210,402,009	3640	23,716,000,000

Retained earnings – lines 3660 to 3849

3660	5,128,401,304	3680	-57,499,295	3701	-500,000
3740	-1,000,000	3849	5,069,402,009		

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

Description

Sequence number **0003** 01

Other comprehensive income – lines 7000 to 7020

7008	228,856

Revenue – lines 8000 to 8299

8000	5,988,000,000	8089	5,988,000,000	8299	5,988,000,000

Cost of sales – lines 8300 to 8519

8320	2,900,000,000	8518	2,900,000,000	8519	3,088,000,000

Operating expenses – lines 8520 to 9369

8523	10,294,276	8570	70,589,830	8623	30,040,492
8670	738,937,120	8710	417,000,000	9284	947,718,787
9367	2,214,580,505	9368	5,114,580,505	9369	873,419,495

Extraordinary items and taxes – lines 9970 to 9999

9970	873,419,495	9990	18,000,338	9995	912,918,452
9998	228,856	9999	-57,270,439		

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			-57,270,439	A
Add:				
Provision for income taxes – current	101	18,000,338		
Provision for income taxes – deferred	102	912,918,452		
Interest and penalties on taxes	103	22,370		
Amortization of tangible assets	104	738,937,120		
Amortization of intangible assets	106	70,589,830		
Charitable donations and gifts from Schedule 2	112	732,573		
Scientific research expenditures deducted per financial statements	118	198,850		
Non-deductible meals and entertainment expenses	121	5,147,138		
Other reserves on lines 270 and 275 from Schedule 13	125	40,478,960		
Reserves from financial statements – balance at the end of the year	126	1,770,546,656		
Income or loss for tax purposes – partnerships	129	12,429,870		
Subtotal of additions		3,570,002,157 ▶	3,570,002,157	
Other additions:				
Capital items expensed	206	18,855,023		
Financing fees deducted in books	216	4,071,052		
Non-deductible legal and accounting fees	228	267,810		

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	CCRA true up	6,804,600
2	Capital contributions received 12(1)(x)	145,098,473
3	LTIP expense	3,893,717
4	Union share grant expenses	4,530,409
5	Reverse insurance proceeds capitalized for tax	635,754
6	Prior year Ontario apprenticeship underaccrual	396,087
7	Loss on housing guarantee	22,499
8	Donation amounts accrued and paid in 2019	500,000
	Total of column 2	161,881,539

Total of column 2 ▶	296	161,881,539		
Subtotal of other additions	199	185,075,424 ▶	185,075,424	
Total additions	500	3,755,077,581 ▶	3,755,077,581	B
Amount A **plus** amount B			3,697,807,142	C
Deduct:				
Capital cost allowance from Schedule 8	403	1,534,853,527		
Other reserves on line 280 from Schedule 13	413	40,305,704		
Reserves from financial statements – balance at the beginning of the year	414	1,711,665,237		
Contributions to deferred income plans from Schedule 15	417	42,521,082		

Subtotal of deductions	3,329,345,550 ▶	3,329,345,550

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Deduction under 20(1)(e) ITA	4,615,855
2	Capitalized interest expenses (a/c 761401/761402)	53,041,781
3	Capitalized operation, maintenance & admin.	73,276,186
4	Capitalized OPEB expenses	26,854,936
5	Capitalized removal costs	4,090,537
6	Environmental payments	21,282,827
7	Capital contributions - 13(7.4) election	145,098,473
8	Bond premium/discount amortization (net of P&L credit)	800,379
9	S. 18(9.1) deduction	135,474
10	Landscaping adjustment	4,784,527
11	Insurance proceeds	3,818,024
12	Prior year Ontario ITC overaccrual	255,047
13	2018 ARO Valuation Adjustment	1,002,477
14	Unrealized mark to market loss on interest rate swaps	412,940
15	Current year Ontario co-op overaccrual	247,164
16	Current year OBRI Accrual	140,000
	Total of column 2	339,856,627

Total of column 2	339,856,627 ▶	396	339,856,627	
Subtotal of other deductions		499	339,856,627 ▶	339,856,627
Total deductions		510	3,669,202,177 ▶	3,669,202,177 D

Net income (loss) for income tax purposes (amount C **minus** amount D) . . . . 28,604,965 E

Enter amount E on line 300 of the T2 return.

Attached Schedule with Total

Line 206 – Capital items expensed

Title Line 206 – Capital items expensed

Description	Operator (Note)	Amount	
Equipment under $2K (GL 620510)		1,014,531	98
Computer Application Software (GL 620046)	+	2,552,172	11
Computer System Software (GL 620040)	+	121,158	68
Project Cancellation Costs (GL 670000)	+	15,167,160	00
	Total	18,855,022	77

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 216 – Financing fees deducted in books

Title Line 216 – Financing fees deducted in books

Description	Operator (Note)	Amount	
Amortization of Underwriting fee (GL #761780)		2,820,986	44
Amortization of Prospectus fee (GL #761790)	+	261,108	13
Amortization of Upfront Loan fee (included in GL #761730)	+	988,957	00
	+		
	Total	4,071,051	57

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 129 – Income or loss for tax purposes – partnerships

Title Line 129 – Income or loss for tax purposes – partnerships

Explanatory note

Partnership Name: Hydro One Sault Ste Marie Holdings II LP ("HOSSMH II LP")
Partnership Business Number: 81254 0136 RZ0001

Partnership Name: Niagra Reinforcement Limited Partnership ("NRP LP")
Partnership Business Number: 79140 1334 RZ0001

Description	Operator (Note)	Amount	
HOSSMH II LP Business Income - Box 104		12,305,768	30
HOSSMH II LP Interest Income - Box 128	+	129,400	03
Less: HOSSMH II LP Charitable Donations - Box 182	-	5,298	41
NRP LP	+		
	Total	12,429,869	92

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Deduction summary as per paragraph 20(1)(e) of the ITA

Federal

Deduction summary as per paragraph 20(1)(e) of the ITA

	Description	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	E Annual deduction (This amount is posted to one of the lines 395 of Schedule 1)	F Balance at the end of the year
1.	2014 Underwriting Fees	2014-01-01	2,646,500	2,118,650	527,850	
2.	2015 Underwriting Fees ($350M/5YRS 0.3%)	2015-04-30	105,000	63,058	21,000	20,942
3.	2016 Underwriting Fees ($500M/5YRS 0.35% + $500M/20YRS 0.	2016-02-24	5,460,000	2,186,992	1,092,000	2,181,008
4.	2016 Underwriting Fees ($500M/3YRS 0.25% + $450M/31YRS 0.	2016-11-18	3,500,000	1,401,918	700,000	1,398,082
5.	2014 Prospectus Fees	2014-01-01	113,279	90,686	22,593	
6.	2015 Prospectus Fees	2015-04-30	4,390	2,636	878	876
7.	2016 Prospectus Fees ($1,350M of new debt)	2016-02-24	207,156	82,976	41,431	82,749
8.	2016 Prospectus Fees ($950M of new debt)	2016-11-18	149,199	59,762	29,840	59,597
9.	2014 Upfront Fees	2014-06-01	600,000	480,329	119,671	
10.	2015 Upfront Fees	2015-06-01	1,560,000	936,855	312,000	311,145
11.	2016 Upfront Loan Fees ($2.3B of new debt)	2016-08-15	1,438,109	576,032	287,622	574,455
12.	2014 Legal Fees	2014-01-01	45,898	36,746	9,152	
13.	2015 Legal Fees	2015-01-01	66,396	39,895	13,279	13,222
14.	2015 Legal Fees	2015-11-05	63,475	27,566	12,695	23,214
15.	2016 Legal Fees	2016-01-01	211,970	84,904	42,394	84,672
16.	2017 Upfront Fees	2017-06-01	920,000	184,000	184,000	552,000
17.	2018 Prospectus Additions ($300M/3 years + $350M/7 years + $	2018-06-21	202,252		40,450	161,802
18.	2018 Underwriting Additions ($300M/3 years + $350M/7 years +	2018-06-21	5,795,000		1,159,000	4,636,000
		Totals	23,088,624	8,373,005	4,615,855	10,099,764

Deduction as per paragraph 20(1)(e) of the ITA

This workchart allows you to determine the tax deduction as per paragraph 20(1)(e) of the Income Tax Act (ITA). It relates to the expenses of issuing or selling shares, units or interests and expenses of borrowing money.

Ensure that any of these expenses deducted in the financial statements have been added back on line 216, "Financing fees deducted in books," and/or on line 235, "Share issue expense" to Schedule 1, if applicable.

* If the check box was selected, the annual deduction will be equal to the amount in column C.

1 Description: 2014 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2014-01-01	2,646,500	2,118,650	527,850	529,300	527,850	

2 Description: 2015 Underwriting Fees ($350M/5YRS 0.3%)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-04-30	105,000	63,058	41,942	21,000	21,000	20,942

3 Description: 2016 Underwriting Fees ($500M/5YRS 0.35% + $500M/20YRS 0.392% + $350M/30YRS 0.5%)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-02-24	5,460,000	2,186,992	3,273,008	1,092,000	1,092,000	2,181,008

4 Description: 2016 Underwriting Fees ($500M/3YRS 0.25% + $450M/31YRS 0.5%)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-11-18	3,500,000	1,401,918	2,098,082	700,000	700,000	1,398,082

5 Description: 2014 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / 365	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2014-01-01	113,279	90,686	22,593	22,656	22,593	

6 Description: 2015 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-04-30	4,390	2,636	1,754	878	878	876

7 Description: 2016 Prospectus Fees ($1,350M of new debt)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-02-24	207,156	82,976	124,180	41,431	41,431	82,749

8 Description: 2016 Prospectus Fees ($950M of new debt)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-11-18	149,199	59,762	89,437	29,840	29,840	59,597

9 Description: 2014 Upfront Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2014-06-01	600,000	480,329	119,671	120,000	119,671	

10 Description: 2015 Upfront Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-06-01	1,560,000	936,855	623,145	312,000	312,000	311,145

11 Description: 2016 Upfront Loan Fees ($2.3B of new debt)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-08-15	1,438,109	576,032	862,077	287,622	287,622	574,455

12 Description: 2014 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2014-01-01	45,898	36,746	9,152	9,180	9,152	

13 Description: 2015 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-01-01	66,396	39,895	26,501	13,279	13,279	13,222

14 Description: 2015 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2015-11-05	63,475	27,566	35,909	12,695	12,695	23,214

15 Description: 2016 Legal Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2016-01-01	211,970	84,904	127,066	42,394	42,394	84,672

16 Description: 2017 Upfront Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2017-06-01	920,000	184,000	736,000	184,000	184,000	552,000

17 Description: 2018 Prospectus Additions ($300M/3 years + $350M/7 years + $750M/3 years)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2018-06-21	202,252		202,252	40,450	40,450	161,802

18 Description: 2018 Underwriting Additions ($300M/3 years + $350M/7 years + $750M/3 years)

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2018-06-21	5,795,000		5,795,000	1,159,000	1,159,000	4,636,000

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers
  - the eligible amount of gifts of certified cultural property
  - the eligible amount of gifts of certified ecologically sensitive land or
  - the additional deduction for gifts of medicine made before March 22, 2017
- All legislative references are to the federal Income Tax Act, unless stated otherwise.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts can be carried forward for 5 years except for gifts of certified ecologically sensitive land made after February 10, 2014, which can be carried forward for 10 years. Provincial food donation tax credits must be applied in the current tax year.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift made before March 22, 2017, to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File one completed copy of this schedule with your T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
[redacted]	500
	500
	500
	500
	500
	500
	500
	500
	500
	1,000
	1,000
	1,000
	1,500
	2,500
	4,500
	5,000
	5,000
	10,000
	10,000
	15,000
	20,000
	25,000
	25,000
	30,000
	50,000
	112,000
	125,000
	129,275
	50,000

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
[redacted]	50,000
	50,000
	5,298
Subtotal	732,573
Add: Total donations of less than $100 each	
Total donations in current tax year	732,573

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year		1,215,058	A	1,215,058	1,215,058
Charitable donations expired after 5 tax years*	239				
Charitable donations at the beginning of the current tax year (amount A **minus** line 239)	240	1,215,058		1,215,058	1,215,058
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1 Net Income (Loss) for Income Tax Purposes)	210	732,573		732,573	732,573
Subtotal (line 250 **plus** line 210)		732,573	B	732,573	732,573
Subtotal (line 240 **plus** amount B)		1,947,631	C	1,947,631	1,947,631
Adjustment for an acquisition of control	255				
Total charitable donations available (amount C **minus** line 255)		1,947,631	D	1,947,631	1,947,631
Amount applied in the current year against taxable income (cannot be more than amount L in Part 2) (enter this amount on line 311 of the T2 return)	260	1,947,631		1,947,631	1,947,631
Charitable donations closing balance (amount D **minus** line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) . . . **262** ______

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) . . . ______ 1

Enter amount 1 on line 420 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the Taxation Act, 2007 (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) . . . **263** ______

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) . . . ______ 2

Enter amount 2 on line 570 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia Income Tax Act.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016 and before January 1, 2020) . . . **265** ______

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) . . . ______ 3

Enter amount 3 on line 683 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia Income Tax Act.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2017-12-31	750,089	750,089	750,089
2nd prior year	2016-12-31	233,603	233,603	233,603
3rd prior year	2015-12-31	226,366	226,366	226,366
4th prior year	2015-11-04	5,000	5,000	5,000
5th prior year	2015-10-31			
6th prior year*	2014-12-31			
7th prior year	2013-12-31			
8th prior year	2012-12-31			
9th prior year	2011-12-31			
10th prior year	2010-12-31			
11th prior year	2009-12-31			
12th prior year	2008-12-31			
13th prior year	2007-12-31			
14th prior year	2006-12-31			
15th prior year	2005-12-31			
16th prior year	2004-12-31			
17th prior year	2003-12-31			
18th prior year	2002-12-31			
19th prior year	2001-12-31			
20th prior year	2000-12-31			
21st prior year*	1999-12-31			
Total (to line A)		1,215,058	1,215,058	1,215,058

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %			21,453,724 E
Taxable capital gains arising in respect of gifts of capital property included in Part 1 **	225		
Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01)	227		
The amount of the recapture of capital cost allowance in respect of charitable donations	230		
Proceeds of disposition, **less** outlays and expenses**		F	
Capital cost**		G	
Amount F or G, whichever is less	235		
Amount on line 230 or 235, whichever is less		H	
Subtotal (**add** line 225, 227, and amount H)		I	
Amount I **multiplied** by 25 %			J
Subtotal (amount E **plus** amount J)			21,453,724 K
Maximum allowable deduction for charitable donations (enter amount D from Part 1, amount K, or net income for tax purposes, whichever is less)			1,947,631 L

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

	Line	Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			M		
Gifts of certified cultural property expired after 5 tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year (amount M **minus** line 439)	440				
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			N		
Subtotal (line 440 **plus** amount N)			O		
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			P		
Gifts of certified cultural property closing balance (amount O **minus** amount P)	480				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2017-12-31			
2nd prior year	2016-12-31			
3rd prior year	2015-12-31			
4th prior year	2015-11-04			
5th prior year	2015-10-31			
6th prior year*	2014-12-31			
7th prior year	2013-12-31			
8th prior year	2012-12-31			
9th prior year	2011-12-31			
10th prior year	2010-12-31			
11th prior year	2009-12-31			
12th prior year	2008-12-31			
13th prior year	2007-12-31			
14th prior year	2006-12-31			
15th prior year	2005-12-31			
16th prior year	2004-12-31			
17th prior year	2003-12-31			
18th prior year	2002-12-31			
19th prior year	2001-12-31			
20th prior year	2000-12-31			
21st prior year*	1999-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 4 – Gifts of certified ecologically sensitive land

	Line	Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			Q		
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount Q **minus** line 539)	540				
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include this amount on line 112 of Schedule 1)	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include this amount on line 112 of Schedule 1)	520				
Subtotal (**add** lines 550, 510, and 520)			R		
Subtotal (line 540 **plus** amount R)			S		
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			T		
Gifts of certified ecologically sensitive land closing balance (amount S **minus** amount T)	580				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date

Year of origin:		Federal	Québec	Alberta
1st prior year	2017-12-31			
2nd prior year	2016-12-31			
3rd prior year	2015-12-31			
4th prior year	2015-11-04			
5th prior year	2015-10-31			
6th prior year*	2014-12-31			
7th prior year	2013-12-31			
8th prior year	2012-12-31			
9th prior year	2011-12-31			
10th prior year	2010-12-31			
11th prior year*	2009-12-31			
12th prior year	2008-12-31			
13th prior year	2007-12-31			
14th prior year	2006-12-31			
15th prior year	2005-12-31			
16th prior year	2004-12-31			
17th prior year	2003-12-31			
18th prior year	2002-12-31			
19th prior year	2001-12-31			
20th prior year	2000-12-31			
21st prior year*	1999-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 5 – Additional deduction for gifts of medicine

		Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			U		
Additional deduction for gifts of medicine expired after 5 tax years*	639				
Additional deduction for gifts of medicine at the beginning of the current tax year (amount U **minus** line 639)	640				
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	650				
Additional deduction for gifts of medicine made before March 22, 2017:					
Proceeds of disposition	602				
Cost of gifts of medicine made before March 22, 2017	601				
Subtotal (line 602 **minus** line 601)			V		
Amount V **multiplied** by 50 %			W		
Eligible amount of gifts	600				

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . **610** ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . ______

where:

a is the **lesser** of line 601 and amount W

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

		Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			X		
Subtotal (line 640 **plus** amount X)			Y		
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			Z		
Additional deduction for gifts of medicine closing balance (amount Y **minus** amount Z)	680				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2017-12-31			
2nd prior year	2016-12-31			
3rd prior year	2015-12-31			
4th prior year	2015-11-04			
5th prior year	2015-10-31			
6th prior year*	2014-12-31			
7th prior year	2013-12-31			
8th prior year	2012-12-31			
9th prior year	2011-12-31			
10th prior year	2010-12-31			
11th prior year	2009-12-31			
12th prior year	2008-12-31			
13th prior year	2007-12-31			
14th prior year	2006-12-31			
15th prior year	2005-12-31			
16th prior year	2004-12-31			
17th prior year	2003-12-31			
18th prior year	2002-12-31			
19th prior year	2001-12-31			
20th prior year	2000-12-31			
21st prior year*	1999-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2017-12-31	
2nd prior year	2016-12-31	
3rd prior year	2015-12-31	
4th prior year	2015-11-04	
5th prior year	2015-10-31	
6th prior year*	2014-12-31	
7th prior year	2013-12-31	
8th prior year	2012-12-31	
9th prior year	2011-12-31	
10th prior year	2010-12-31	
11th prior year	2009-12-31	
12th prior year	2008-12-31	
13th prior year	2007-12-31	
14th prior year	2006-12-31	
15th prior year	2005-12-31	
16th prior year	2004-12-31	
17th prior year	2003-12-31	
18th prior year	2002-12-31	
19th prior year	2001-12-31	
20th prior year	2000-12-31	
21st prior year*	1999-12-31	
Total		

* These gifts expired in the current year.

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Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a),(a.1), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- All legislative references are to the federal *Income Tax Act*.
- The calculations in this schedule apply only to private or subject corporations.
- A recipient corporation is **connected** with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A1 – Enter "X" if dividends received from a foreign source.
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H and I **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing column J and K use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business Number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividends under section 83 230
1			2			
					Total of column E (enter amount on line 402 of Schedule 1)	

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1] **240**	F1 Eligible dividends (included in column F)	F2	G Dividends included in column F that was received **before** 2016 **241**	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) **250**	I Dividend refund of the **connected** payer corporation (for tax year in column D)[note 2] **260**	J Part IV tax before deductions. Dividends (from column G) received **before** 2016 **multiplied** by 33 1/3%[note 3] **270**	K Part IV tax before deductions. Dividends received **after** 2015 (column F **minus** column G) **multiplied** by 38 1/3%[note 4] **275**
1								
	Total of column F (include this amount on line 320 of the T2 Return)						**Total of column J** (enter amount on line a in Part 2)	**Total of column K** (enter amount on line b in Part 2)

1 If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270 or column 275 as applicable according to the date received. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For dividends received **before** 2016 from **connected** corporations, Part IV tax on dividends is equal to: column G **multiplied** by column I **divided** by column H.

4 For dividends received **after** 2015 from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by the result of column F **minus** column G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received **before** 2016, before deductions (total of column J in part 1) ...... a
Part IV tax on dividends received **after** 2015, before deductions (total of column K in part 1) .... b
Part IV tax before deductions (amount a **plus** amount b) .... ▶ L

Deduct:
Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) 320
Subtotal (amount L **minus** line 320) M

Deduct:
Current-year non-capital loss claimed to reduce Part IV tax .... 330 c
Non-capital losses from previous years claimed to reduce Part IV tax .... 335 d
Current-year farm loss claimed to reduce Part IV tax .... 340 e
Farm losses from previous years claimed to reduce Part IV tax .... 345 f

Total losses applied against Part IV tax (total of amounts c to f) g

If your tax year begins after December 31, 2015:
Amount g **multiplied** by 38 1 / 3 % .... h

If your tax year begins before January 1, 2016:
Amount b or M whichever is less
÷ 38 1 / 3 % ... = 1
Amount 1 or g, whichever is less 2
Amount g **minus** amount 2 3
Amount 2 x 38 1 / 3 % = i
Amount 3 x 33 1 / 3 % = j
Subtotal (amount i **plus** amount j) k

Amount h or amount k, whichever applies depending on your tax year start date .... N
Part IV tax payable (amount M **minus** amount N, if negative enter "0") 360
(enter amount on line 712 of the T2 return)

Part of the amount on line 360 attributable to:
– Eligible dividends received from unconnected corporations N1
– Taxable dividends received from connected corporations which generated a dividend refund from their ERDTOH account N2
– Other taxable dividends N3

Note: The total of amounts N1, N2 and N3 cannot be greater than the amount on line 360. For more information, consult the Help (F1).

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	O Name of connected recipient corporation 400	P Business Number 410	Q Tax year-end of connected recipient corporation in which the dividends in column R were received YYYY/MM/DD 420	R Taxable dividends paid to connected corporations 430	R1 Eligible dividends (included in column R)
1	Hydro One Inc.	[redacted]	2018-12-31	500,000	500,000
			Total of column R	500,000	

Total taxable dividends paid in the tax year to other than connected corporations 450

Eligible dividends (included in line 450) 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund
(total of column R **plus** line 450) 460 500,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)				500,000
Other dividends paid in the tax year (total of 510 to 540)				
Total dividends paid in the tax year			500	500,000
Deduct:				
Dividends paid out of capital dividend account	510			
Capital gains dividends	520			
Dividends paid on shares described in subsection 129(1.2)	530			
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540			
Subtotal (total of lines 510 to 540)			►	S
Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount S)				500,000 T

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				28,604,965	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)			b		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Subtotal (total of amounts a to d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")					C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)					E
Add: (decrease a loss)					
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0")					G

If amount G is negative, enter it on line 110 as a positive.

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		891,343,131	e		
Deduct: Non-capital loss expired (note 1)	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102	891,343,131	▶	891,343,131	H
Add:					
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation	105		g		
Current-year non-capital loss (from amount G)	110		h		
Subtotal (amount g **plus** amount h)			▶		I
Subtotal (amount H **plus** amount I)				891,343,131	J

Note 1: A non-capital loss expires as follows:

- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i		
Section 80 – Adjustments for forgiven amounts	140		j		
Subsection 111(10) – Adjustments for fuel tax rebate			j.1		
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130		k		
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3)	135		l		
Subtotal (total of amounts i to l)			▶		K
Non-capital losses before any request for a carryback (amount J **minus** amount K)				891,343,131	L

Deduct – Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901		m		
Second previous tax year to reduce taxable income	902		n		
Third previous tax year to reduce taxable income	903		o		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r		
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)			▶		M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180			891,343,131	N

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200	117,088	a		
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205		b		
Subtotal (amount a **plus** amount b)		117,088	▶	117,088	A
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	250		c		
Section 80 – Adjustments for forgiven amounts	240		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **minus** amount B)				117,088	C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	210			22,499	D
Unused non-capital losses that expired in the tax year (note 4)			e		
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5)			f		
Enter amount e or f, whichever is less	215		g		
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220				E
Subtotal (total of amounts C to E)				139,587	F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (note 6)			225		G
Capital losses before any request for a carryback (amount F **minus** amount G)				139,587	H

Deduct – Request to carry back capital loss to (note 7):

	Capital gain (100%)		Amount carried back (100%)			
First previous tax year		951		h		
Second previous tax year		952		i		
Third previous tax year		953		j		
Subtotal (total of amounts h to j)				▶		I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)				280	139,587	J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired (note 8)	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302		▶		A
Add:					
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305		c		
Current-year farm loss (amount F in Part 1)	310		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year Enter amount g on line 334 of the T2 Return.	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9)	335		h		
Subtotal (total of amounts e to h)			▶		D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – Request to carry back farm loss to:					
First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)			▶		F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)			380		G

Note 8: A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business		**485**		A
Minus the deductible farm loss:				
(amount A above ______ – $2,500) **divided** by 2 = ______ a				
Amount a or $ 15,000 (note 10), whichever is less				b
	2,500 c			
Subtotal (amount b **plus** amount c)	2,500 ▶		2,500	B
Current-year restricted farm loss (amount A **minus** amount B)				C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d	
Deduct: Restricted farm loss expired (note 11)	**400**		e	
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	**402**	▶		D
Add:				
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	**405**		f	
Current-year restricted farm loss (from amount C)	**410**		g	
Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.				
Subtotal (amount f **plus** amount g)		▶		E
Subtotal (amount D **plus** amount E)				F
Deduct:				
Restricted farm losses from previous tax years applied against current farming income	**430**		h	
Enter amount h on line 333 of the T2 return.				
Section 80 – Adjustments for forgiven amounts	**440**		i	
Other adjustments	**450**		j	
Subtotal (total of amounts h to j)		▶		G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)				H

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	**941**		k	
Second previous tax year to reduce farming income	**942**		l	
Third previous tax year to reduce farming income	**943**		m	
Subtotal (total of amounts k to m)		▶		I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	**480**			J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after 7 tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶		A
Add: Current-year listed personal property loss (from Schedule 6)			510		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Listed personal property losses from previous tax years applied against listed personal property gains	530		c		
Enter amount c on line 655 of Schedule 6.					
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)			▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E
Deduct – Request to carry back listed personal property loss to:					
First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)			▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)			580		G

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number **600**	Tax year ending yyyy/mm/dd **602**	Corporation's share of limited partnership loss **604**	Corporation's at-risk amount **606**	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses **608**	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6) **620**
1.							
						Total (enter this amount on line 222 of Schedule 1)	

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number **630**	Tax year ending yyyy/mm/dd **632**	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary **634**	Corporation's at-risk amount **636**	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses **638**	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) **650**
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number **660**	Limited partnership losses at the end of the previous tax year **662**	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary **664**	Current-year limited partnership losses (from line 620) **670**	Limited partnership losses applied in the current year (must be equal to or less than line 650) **675**	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) **680**
1.						
				Total (enter this amount on line 335 of the T2 return)		

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A				N/A		
1st preceding taxation year 2017-12-31	120,276,804	N/A		N/A			120,276,804
2nd preceding taxation year 2016-12-31	549,209,136	N/A		N/A			549,209,136
3rd preceding taxation year 2015-12-31	219,765,360	N/A		N/A			219,765,360
4th preceding taxation year 2015-11-04	2,091,831	N/A		N/A			2,091,831
5th preceding taxation year 2015-10-31		N/A		N/A			
6th preceding taxation year 2014-12-31		N/A		N/A			
7th preceding taxation year 2013-12-31		N/A		N/A			
8th preceding taxation year 2012-12-31		N/A		N/A			
9th preceding taxation year 2011-12-31		N/A		N/A			
10th preceding taxation year 2010-12-31		N/A		N/A			
11th preceding taxation year 2009-12-31		N/A		N/A			
12th preceding taxation year 2008-12-31		N/A		N/A			
13th preceding taxation year 2007-12-31		N/A		N/A			
14th preceding taxation year 2006-12-31		N/A		N/A			
15th preceding taxation year 2005-12-31		N/A		N/A			
16th preceding taxation year 2004-12-31		N/A		N/A			
17th preceding taxation year 2003-12-31		N/A		N/A			
18th preceding taxation year 2002-12-31		N/A		N/A			
19th preceding taxation year 2001-12-31		N/A		N/A			
20th preceding taxation year 2000-12-31		N/A		N/A			*
Total	891,343,131						891,343,131

* **This balance expires this year and will not be available next year.**

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Use this schedule if, during the tax year, your corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references are to the Income Tax Regulations.
- For more information, see the T2 Corporation – Income Tax Guide.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year.*		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes	103		143		
Newfoundland and Labrador Offshore	004 Yes	104		144		
Prince Edward Island	005 Yes	105		145		
Nova Scotia	007 Yes	107		147		
Nova Scotia Offshore	008 Yes	108		148		
New Brunswick	009 Yes	109		149		
Quebec	011 Yes	111		151		
Ontario	013 Yes	113		153		
Manitoba	015 Yes	115		155		
Saskatchewan	017 Yes	117		157		
Alberta	019 Yes	119		159		
British Columbia	021 Yes	121		161		
Yukon	023 Yes	123		163		
Northwest Territories	025 Yes	125		165		
Nunavut	026 Yes	126		166		
Outside Canada	027 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in subsection 400(2).

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. If the corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
26,657,334		26,657,334	3,065,593

Ontario basic income tax (from Schedule 500)	270	3,065,593		
Ontario small business deduction (from Schedule 500)	402			
Subtotal (line 270 **minus** line 402)		3,065,593	3,065,593	5A
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal (line 276 **plus** line 277)				5B
Gross Ontario tax (amount 5A **plus** amount 5B)			3,065,593	5C
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario political contributions tax credit (from Schedule 525)	415			
Ontario non-refundable tax credits (total of lines 404 to 415)				5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")			3,065,593	5E
Ontario research and development tax credit (from Schedule 508)	416		434,123	
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")			2,631,470	5F
Ontario corporate minimum tax credit (from Schedule 510)	418			
Ontario community food program donation tax credit for farmers (from Schedule 2)	420			
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative enter "0")			2,631,470	5G
Ontario corporate minimum tax (from Schedule 510)	278	19,939,987		
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal (line 278 **plus** line 280)		19,939,987	19,939,987	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)			22,571,457	5I
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	951,487		
Ontario apprenticeship training tax credit (from Schedule 552)	454	2,577,227		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Ontario refundable tax credits (total of lines 450 to 470)		3,528,714	3,528,714	5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets) Include this amount on line 255.	290		19,042,743	

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits 255 19,042,743

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Also use this schedule to make a designation under paragraph 111(4)(e) of the *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in Guide T4012, *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the Income Tax Act

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . . . 050 1 Yes [ ] 2 No [X]

If **yes**, attach a statement specifying which properties such a designation applies to.

Part 1 – Shares

1 Number of shares 100	2 Name of corporation in which the shares are held 105	3 Class of shares 106	4 Date of Acquisition YYYY/MM/DD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150	Foreign source
			Totals					

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 . . . . 160 ______

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . ______ **A**

Part 2 – Real estate (Do not include losses on depreciable property)

	1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of Acquisition YYYY/MM/DD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	Foreign source	
1	[redacted]	2017-10-24	390,000	390,000	22,499	-22,499		
		Totals	390,000	390,000	22,499	-22,499		**B**

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYY/MM/DD 305	3 Name of bond issuer 307	4 Date of Acquisition YYYY/MM/DD 310	5 Proceeds of disposition 320	6 Adjusted cost base 330	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350	Foreign source	
			Totals						**C**

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property 400	2 Date of Acquisition YYYY/MM/DD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450	Foreign source
Totals						D

Note
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of Acquisition YYYY/MM/DD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550	Foreign source
Totals						E

Note
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of Acquisition YYYY/MM/DD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 650	Foreign source
Totals						

Deduct: Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, *Corporation Loss Continuity and Application*) . . . . 655 ________

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . ________ F

Note
Net listed personal property losses can only be applied against listed personal property gains.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation 900	2 Shares, enter 1; debt, enter 2 905	3 Date of Acquisition YYYY/MM/DD 910	4 Proceeds of disposition 920	5 Adjusted cost base 930	6 Outlays and expenses from disposition 940	7 Loss only (column 4 **minus** columns 5 and 6) 950	Foreign source
Totals							

Allowable business investment losses (ABILs) . . . . Total of Column 7 ________ x 50.0000 % = ________ G

Enter amount G on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

Note
Properties listed in Part 7 should not be included in any other parts of this schedule.

Part 8 – Capital gains or losses

Total of amounts A to F (do not include amount F if it is a loss)		-22,499	H	
Add:				Foreign source
Capital gains dividend received in the year	875		I	☐
Capital gains reserve opening balance (from Part 1 of Schedule 13, *Continuity of Reserves,* enter the amount from line 8, *Balance at the beginning of the year* **plus** the amount from line 9, *Transfer on an amalgamation or the wind–up of a subsidiary*)	880		J	
Subtotal (total of amounts H to J)		-22,499	K	
Deduct: Capital gains reserve closing balance (from Schedule 13)	885		L	
Capital gains or losses, excluding ABILs (amount K **minus** amount L)	890	-22,499	M	

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) .... -22,499 N

Deduct the following amounts included in amount N, that are subject to the zero inclusion rate:

Note
When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only part of the taxpayer's capital gain on disposition of the property. See section 38.2 of the Act for more information.

Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under subparagraphs 38(a.1)(i) and (iii) of the Act	895		a			Foreign source ☐
Gain on the donation to a qualified donee of ecologically sensitive land under paragraph 38(a.2) of the Act*	896		b			Foreign source ☐
Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*)			b-2			Foreign source ☐
Subtotal (amount a **plus** amount b **plus** b-2)			▶		O	
Subtotal (amount N **minus** amount O)				-22,499	P	

Add:
Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12) of the Act:

Exemption threshold at time of disposition	897		c		
The total of all capital gains from the disposition of the actual property	898		d		
Amount c or amount d, whichever is less					Q ☐ Foreign source
Taxable capital gains under section 34.2 of the Act (line 275 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)		x 2 =	899		R
Subtotal (total of amounts P to R)				-22,499	S

Deduct:

Allowable capital losses under section 34.2 of the Act (line 285 of Schedule 73, *Income Inclusion Summary for Corporations that are Members of Partnerships*)		x 2 =	901		T
Total capital gains or losses (amount S **minus** amount T)				-22,499	U

Taxable capital gains or total capital losses

Total capital losses (amount U, if amount U is negative; if amount U is positive, enter "0") .... 22,499 V
Enter amount V on line 210 of Schedule 4.

Taxable capital gains (if amount U is positive, enter amount U ______ multiplied by 50.0000 %;
if amount U is negative, enter "0") .... W
Enter amount W on line 113 of Schedule 1.

* Do not include gains on donations of ecologically sensitive land to a private foundation.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** Yes [ ] No [X]

	1 Class number * 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) 203	4 Adjustments and transfers (see note 2 below) 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see notes 3 and 7 below) 211	7 Reduced undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5 **minus** column 6) (see note 7 below)	8 CCA rate % (see note 4 below) 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) (see note 5 below) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) (see notes 6 and 7 below) 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		4,986,870,627	67,158,336		596,354	33,280,991	5,020,151,618	4	0	0	200,806,065	4,852,626,544
2.	1b		38,847			0		38,847	6	0	0	2,331	36,516
3.	2		2,848,858,264			0		2,848,858,264	6	0	0	170,931,496	2,677,926,768
4.	3		294,219,017	255,439		0	127,720	294,346,736	5	0	0	14,717,337	279,757,119
5.	6		81,665,114	6,884,152		0	3,442,076	85,107,190	10	0	0	8,510,719	80,038,547
6.	8		235,844,051	77,056,552	227,823	215,036	38,420,758	274,492,632	20	0	0	54,898,526	258,014,864
7.	9		9,690,021			0		9,690,021	25	0	0	2,422,505	7,267,516
8.	10		238,054,863	22,656,651	283,387	4,280,567	9,188,042	247,526,292	30	0	0	74,257,888	182,456,446
9.	10	Class 10.1	2,533,735	67,800		0	33,900	2,567,635	30	0	0	770,291	1,831,244
10.	12		48,366,423	87,319,241		0	43,659,621	92,026,043	100	0	0	92,026,043	43,659,621
11.	13	2017 "Get Local" Office Upgrade		40		0	3	40	NA	0	0	3	37
12.	13	255 Matheson Mississauga (WBS	419,963			0		419,963	NA	0	0	148,247	271,716
13.	13	483 Bay Street (WBS 300042991	15,191,741	410,710		0	25,669	15,602,451	NA	0	0	1,836,133	13,766,318
14.	13	Arnprior Forestry Work Centre (V	138,073			0		138,073	NA	0	0	28,561	109,512
15.	13	Atrium on Bay (WBS 300040666	25,482			0		25,482	NA	0	0	8,995	16,487
16.	13	Lionhead (WBS 700015140)	12,340			0		12,340	NA	0	0	4,356	7,984
17.	13	Newmarket Garage (WBS 30004(	42,422			0		42,422	NA	0	0	14,975	27,447
18.	13	Newmarket SC (WBS 700016578	4,234			0		4,234	NA	0	0	1,104	3,130
19.	13	Nipigon (WBS 700011829)	49,475			0		49,475	NA	0	0	17,465	32,010
20.	13	Orillia Forestry Work Centre (WB	153,612			0		153,612	NA	0	0	27,666	125,946
21.	13	Orleans OC (WBS 700010809)	833,766			0		833,766	NA	0	0	291,532	542,234
22.	13	Sudbury (WBS 700010356)	132,850			0		132,850	NA	0	0	16,961	115,889
23.	13	Sudbury 500 Barrydowne (WBS	476,742			0		476,742	NA	0	0	68,617	408,125

	1 Class number * 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) 203	4 Adjustments and transfers (see note 2 below) 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see notes 3 and 7 below) 211	7 Reduced undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5 **minus** column 6) (see note 7 below)	8 CCA rate % (see note 4 below) 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) (see note 5 below) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) (see notes 6 and 7 below) 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
24.	13	Thunder Bay Fleet Garage (WBS	69,144			0		69,144	NA	0	0	19,756	49,388
25.	13	Thunder Bay Fleet Garage (WBS	3,444,801		-100,226	0		3,344,575	NA	0	0	136,595	3,207,980
26.	14	Post-2016	2,056,006			0		2,056,006	NA	0	0	118,437	1,937,569
27.	14.1	Pre-2017 (formerly ECE)	3,340,446,579			0		3,340,446,579	5	0	0	114,700,000	3,225,746,579
28.	14.1		6,319,080	3,946,930		729	1,973,101	8,292,180	5	0	0	414,609	9,850,672
29.	17		129,637,656	32,731,380		0	16,365,690	146,003,346	8	0	0	11,680,268	150,688,768
30.	42		115,374,488	1,478,587		0	739,294	116,113,781	12	0	0	13,933,654	102,919,421
31.	43.2		7,926			0		7,926	50	0	0	3,963	3,963
32.	45		6,735,840			0		6,735,840	45	0	0	3,031,128	3,704,712
33.	46		10,947,190	11,380,124		0	5,690,062	16,637,252	30	0	0	4,991,176	17,336,138
34.	47		7,808,087,039	1,217,165,992		2,949,012	607,108,490	8,415,195,529	8	0	0	673,215,642	8,349,088,377
35.	50		103,995,558	121,449,296	371,581	0	60,724,648	165,091,787	55	0	0	90,800,483	135,015,952
		Totals	20,290,742,969	1,649,961,230	782,565	8,041,698	820,780,065	21,112,690,673				1,534,853,527	20,398,591,539

* Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

Note 2. Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

Note 3. The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

Note 4. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

Note 5. For every entry in column 9, "Recapture of capital cost allowance", there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

Note 6. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Note 7. At the time the program was released, the official CRA Schedule 8 had not yet been updated to take into account the new measures added to subsection 1100(2) ITR, as proposed in the *Notice of Ways and Means Motion to amend the Income Tax Act and the Income Tax Regulations* published on November 21, 2018. Therefore, the amounts calculated in columns 6 and 7 do not reflect these new measures. However, the CCA amount calculated in column 12 takes these new measures into account.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		1,649,550,480		
Additions for tax purposes – Schedule 8 leasehold improvements	+	410,750		
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+	241,998,564		
Other (specify):				
Land additions	+	3,122,000		
Capital items expensed for book purposes (computers)	+	-3,687,863		
Project cancellation costs expensed for book purposes	+	-10,867,159		
Disallowed Class 10.1 Additions	+	14,385		
Suspense related adjustments (see schedule)	+	-13,818,047		
Transfers (see schedule)	+	3,419,936		
Capitalized SRED Expenditures - in serviced	+	2,768,783		
Insurance proceeds capitalized for tax	+	3,818,024		
Less Insurance proceed spend	+	-635,754		
UCC adjustment (on Sch 8 adj column)	+	782,565		
Removal costs (cap for tax but deduct for accounting)	+	-89,280,190		
HOSSM transfer - cost amount included in additions	+	2,035,000		
HOSSM - land transfer tax capitalized	+	1,400,207		
Total additions per books	=	1,791,031,681	►	1,791,031,681
Proceeds up to original cost – Schedule 8 regular classes		8,041,698		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+	-1,867,006		
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
Decrease in CIP ending (excluded from Sch 8 adds)	+	260,413,084		
Future use assets movement	+	6,282,000		
Amounts included in amort expense but not Acc. Amort (see sch)	+	-77,715,233		
HOSSM transfer - acc amortization picked up (without P&L)	+	1,176,000		
DSC exemption impacting expense but not acc amort	+	505,000		
2017 disposal reflected in 2018 continuity	+	296,000		
Total proceeds per books	=	197,131,543	► –	197,131,543
Depreciation and amortization per accounts – Schedule 1			–	809,526,950
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	784,373,188

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		20,410,000,000
Opening net book value	–	19,626,000,000
Net change per financial statements	=	784,000,000

If the amounts from the tax return and the financial statements differ, explain why below.

FS prepared in millions; difference of $373K due to rounding.

Attached Schedule with Total

Tax return – Deductible expenses capitalized for book purposes – Schedule 1

Title Tax return – Deductible expenses capitalized for book purposes – Schedule

Explanatory note

Refer to T2 - Fixed Asset Roll and 8.4 Accting to Tax Adds for details.

Description	Operator (Note)	Amount	
Pension Expenses		42,521,082	00
Capitalized Interest Expenses	+	53,041,781	00
OMA Expenses Capitalized Overhead	+	73,276,186	00
OPEB Expenses	+	26,854,936	00
LTIP Expenses	+	1,441,872	00
Landscaping	+	4,732,000	00
Removal Costs	+	4,090,537	00
Union share grant expenses	+	5,059,391	00
Capitalized depreciation	+	30,980,779	00
	+		
	Total	241,998,564	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Explanatory note

See 8.4

Description	Operator (Note)	Amount	
Transfers - Accounting transfers		288,572	00
Transfers - I/C Capital Contributions	+	3,953,781	00
Transfers - HOSSM MFA purchase	-	882,791	00
Transfers - DSC Assets in Service	+	60,374	00
	+		
	Total	3,419,936	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Explanatory note

Suspense related amounts - as suspense is part of the additions for tax purposes, any amounts that were credited in the year should be reversed to ensure appropriate amount of additions are reflected.

Description	Operator (Note)	Amount	
Amounts credited to suspense account that needs to be added back			
- CCRA True up (tab 8.8)	-	6,804,600	00
- Project cancellation costs (tab 8.11)	-	4,300,000	00
- Permanent bypass payment (tab 8.9)	-	2,713,447	00
	+		
	Total	-13,818,047	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Explanatory note

Refer to tab T2- Fixed Asset Roll

Description	Operator (Note)	Amount	
CIP Opening - Fixed assets		1,203,370,718	51
CIP Ending - Fixed assets	-	924,914,552	00
CIP Opening - Intangibles	+	40,622,677	00
CIP Ending - Intangibles (T14330000 - Inantigle Assets - CIP) per TB	-	58,665,760	00
	+		
	Total	260,413,083	51

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Explanatory note

Tab 8.13

Description	Operator (Note)	Amount	
Gain/loss on sale of fixed assets		1,867,459	00
Capitalized depreciation	+	30,980,779	00
Asset removal cost	-	89,280,190	00
Amortization of environmental reg asset	-	21,282,827	00
Real estate gain/loss	-	454	00
	+		
	Total	-77,715,233	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	1228185 Ontario Inc.	CA	[redacted]	2					
2.	1937672 Ontario Inc.	CA	[redacted]	2					
3.	1937680 Ontario Inc.	CA	[redacted]	3					
4.	1937681 Ontario Inc.	CA	[redacted]	3					
5.	1938454 Ontario Inc.	CA	[redacted]	3					
6.	1943404 Ontario Inc.	CA	[redacted]	3					
7.	2486267 Ontario Inc.	CA	[redacted]	3					
8.	2486268 Ontario Inc.	CA	[redacted]	3					
9.	2587264 Ontario Inc.	CA	[redacted]	3					
10.	2587265 Ontario Inc.	CA	[redacted]	3					
11.	Haldimand County Energy Inc.	CA	[redacted]	2					
12.	Haldimand County Hydro Inc.	CA	[redacted]	2					
13.	Hydro One B2M Holdings Inc.	CA	[redacted]	3					
14.	Hydro One B2M LP Inc.	CA	[redacted]	3					
15.	Hydro One East-West Tie Inc.	CA	[redacted]	3					
16.	Hydro One Holdings Limited	CA	[redacted]	3					
17.	Hydro One Inc.	CA	[redacted]	1					
18.	Hydro One Indigenous Partnerships	CA	[redacted]	3					
19.	Hydro One Lake Erie Link Managem	CA	[redacted]	3					
20.	Hydro One Limited	CA	[redacted]	3					
21.	Hydro One Remote Communites Inc	CA	[redacted]	3					
22.	Hydro One Sault Ste. Marie Holding	CA	[redacted]	2					
23.	Hydro One Sault Ste. Marie Holding	CA	[redacted]	3					
24.	Hydro One Sault Ste. Marie Inc.	CA	[redacted]	3					
25.	Hydro One Telecom Inc.	CA	[redacted]	3					
26.	Hydro One Telecom Link Limited	CA	[redacted]	3					
27.	Municipal Billing Services Inc.	CA	[redacted]	3					
28.	Norfolk Energy Inc.	CA	[redacted]	3					
29.	Norfolk Power Distribution Inc.	CA	[redacted]	2					
30.	Olympus Corp.	US	[redacted]	3					
31.	Olympus Holding Corp.	US	[redacted]	3					
32.	Woodstock Hydro Services Inc.	CA	[redacted]	2					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11) Canada

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SCHEDULE 11

TRANSACTIONS WITH SHAREHOLDERS, OFFICERS, OR EMPLOYEES

Corporation's name	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

Provide the details of any transactions with shareholders, officers or employees that involve:

- payments the corporation made or amounts credited to the account of shareholders, officers, or employees, which were not part of their remuneration or reimbursement of expenses;
- assets the corporation sold to or purchased from shareholders, officers, or employees, including those for which an election was made under section 85; or
- loans or indebtedness to shareholders, officers, or employees, or persons connected with a shareholder, which were not repaid by the end of the taxation year.

	Relationship code (see note) 100	Payments $ 200	Reimbursement (Other than reimbursement of expenses) $ 300	Loans receivable from, or debts owing to $ 400	Assets sold or purchased $ 500	Does section 85 apply to assets sold or purchased? 550
1	1				1,000,000	Yes [X] No [ ]

Note: Enter the code number of the relationship that applies: (if more than one relationship exists, enter the lowest applicable number)
1 - Shareholder
2 - Officer
3 - Employee

T2 SCH 11 (00)

Canada

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description		Balance at the beginning of the year $	Transfer on an amalgamation or the wind-up of a subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts	☐	110	115			120
Reserve for undelivered goods and services not rendered	X	130 40,478,960	135		173,256	140 40,305,704
Reserve for prepaid rent	☐	150	155			160
Reserve for refundable containers . .	☐	190	195			200
Reserve for unpaid amounts	☐	210	215			220
Other tax reserves	☐	230	235			240
Totals		270 40,478,960	275		173,256	280 40,305,704

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability Long Term	1,535,868,320			98,858,294	1,437,010,026
2	Environmental Long Term	161,389,330			31,930,351	129,458,979
3	Regulatory Assets OPEB & Envi	-197,567,570		157,893,250		-39,674,320
4	Net Regulatory Liabilities	141,610,474		33,434,557		175,045,031
5	Tenant Inducement	4,160,531			2,816,525	1,344,006
6	Asset Retirement Obligations	9,372,563		1,039,966		10,412,529
7	Insurance proceeds reserve	3,528,923			635,754	2,893,169
8	Bonus payable	1,371,809			460,789	911,020
9	Contingent Liabilities	11,266,951		1,131,560		12,398,511
10	DSU	184,946		257,055		442,001
11						
	Reserves from Part 2 of Schedule 13	40,478,960			173,256	40,305,704
	Totals	1,711,665,237		193,756,388	134,874,969	1,770,546,656

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Inc	483 Bay Street Toronto ON M5G 2P5			7,034,989		

T2 SCH 14 (99)

Canada

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Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	72,561,574	[redacted]			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	72,561,574	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	30,040,492	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")	42,521,082	C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

T2 SCH 15 (13)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 29

PAYMENTS TO NON-RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- A corporation that makes payments or credits amounts to non-residents under subsections 202(1) and 105(1) of the *Income Tax Regulations* has to file the applicable information return.
- The corporation has to complete the information below for all amounts paid or credited to non-residents that are listed in Note 1. If the total amount paid or credited is less than $100, you do not have to complete the information for that payee.

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
1	[redacted]		09	6,250
2			09	10,492
3			09	61,529
4			09	627
5			09	3,750
6			09	60,203
7			09	14,669
8			09	91,576
9			09	12,771
10			09	2,623
11			09	22,804

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
12	[redacted]		09	47,561
13			09	15,000
14			09	13,891
15			09	19,532
16			09	6,974
17			09	21,024
18			09	11,098
19			09	50,566
20			09	70,889
21			09	15,116
22			09	46,902
23			09	15,561
24			09	47,543

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
25	[redacted]	[redacted]	09	14,743
26	[redacted]	[redacted]	09	98,693
27	[redacted]	[redacted]	09	282,927
28	[redacted]	[redacted]	09	22,344
29	[redacted]	[redacted]	09	5,000
30	[redacted]	[redacted]	09	5,000
31	[redacted]	[redacted]	09	75,086
32	[redacted]	[redacted]	09	15,408
33	[redacted]	[redacted]	09	47,574
34	[redacted]	[redacted]	09	2,500
35	[redacted]	[redacted]	09	2,500
36	[redacted]	[redacted]	09	56,128
37	[redacted]	[redacted]	09	24,175

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
38	[redacted]		09	5,000
39			09	13,104
40			09	72,750
41			09	15,461
42			09	27,724
43			09	4,807
44			09	1,000
45			09	1,000
46			09	1,000

Note 1: Enter the applicable payment code in column 300:

1 – Royalties
2 – Rents
3 – Management fees/commissions
4 – Technical assistance fees
5 – Research and development fees
6 – Interest
7 – Dividends
8 – Film payments: – motion picture film, or – a film or video tape for use in connection with television
9 – Other services

T2 SCH 29 (99)

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1);
  - to request a credit carryback to one or more previous years;
  - if you are subject to a recapture of ITC; or
  - if you are claiming:
    - the **Ontario Research and Development Tax Credit**;
    - the **Ontario Innovation Tax Credit.**
- Unless otherwise stated, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
    - Expenditures related to child care spaces incurred after March 21, 2017 no longer qualify for the investment tax credit. If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.
- File this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide* and read Information Circular IC78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see guide T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Expenditures for pre-production mining, apprenticeship, or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For tax purposes**,** Canada includes the **exclusive economic zone of Canada** as defined in the *Oceans Act* (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Detailed information (continued)

- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15 % rate.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures***:	
– after March 28, 2012, and before 2014	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred expenditures after March 18, 2007 and before March 22, 2017 (or before 2020 if you entered into a written agreement before March 22, 2017) for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** A transitional relief rate may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraphs (k)(ii) and (iii) of the definition of **specified percentage** in subsection 127(9) for more information.

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . **102** 1 Yes [ ] 2 No [X]

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . **103** ______
Enter on line 350 of Part 8.

* Enter only contributions not already included on Form T661.
Include 80% of the contributions made **after** 2012. For contributions made **before** 2013, include all of the contributions.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**

Total of investments for qualified property and qualified resource property ______ A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year				B1
Credit deemed as a remittance of co-op corporations	210			
Credit expired	215			
Subtotal (line 210 **plus** line 215)			▶	C1
ITC at the beginning of the tax year (amount B1 **minus** amount C1)			220	
Credit transferred on an amalgamation or the wind-up of a subsidiary	230			
ITC from repayment of assistance	235			
Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) ______ x 10 % =	240			
Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) ______ x 5 % =	242			
Credit allocated from a partnership	250			
Subtotal (total of lines 230 to 250)			▶	D1
Total credit available (line 220 **plus** amount D1)				E1
Credit deducted from Part I tax	260			
Credit carried back to previous years (amount H1 in Part 6)		a		
Credit transferred to offset Part VII tax liability	280			
Subtotal (total of line 260, amount a, and line 280)			▶	F1
Credit balance before refund (amount E1 **minus** amount F1)				G1
Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7)			310	
ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310)			320	

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	
2nd previous tax year				Credit to be applied	902	
3rd previous tax year				Credit to be applied	903	
				Total of lines 901 to 903 Enter at amount a in Part 5.		H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5)		I1
Credit balance before refund (from amount G1 in Part 5)		J1
Refund (40 % of amount I1 or J1, whichever is less)		K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter on line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 557 on Form T661)		921,352		
Contributions to agricultural organizations for SR&ED				
Deduct:				
Government assistance, non-government assistance, or contract payment				
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)*	►	+		
Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)*		921,352 ►	350	921,352
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**			360	
Repayments made in the year (from line 560 on Form T661)			370	
Qualified SR&ED expenditures (total of lines 350 to 370)			380	921,352

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures. Capital cost allowance can be claimed for depreciable property acquired for use in SR&ED after 2013.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . **385** 1 Yes ☐ 2 No ☐

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, the amounts for associated corporations will be determined on Schedule 49.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied)	390	
Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million	398	

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation:			$ 8,000,000	
Taxable income for the previous tax year (line 390 in Part 9) or $500,000, whichever is more		x 10 =		A2
Excess ($8,000,000 **minus** amount A2; if negative, enter "0")				B2
$ 40,000,000 **minus** line 398 in Part 9		b		
Amount b **divided** by $ 40,000,000				C2
Expenditure limit for the stand-alone corporation (amount B2 **multiplied** by amount C2)*				D2
For an associated corporation:				
If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49*		400		E2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D2 or E2 ______ x Number of days in the tax year / 365   365 = ______ F2

Your SR&ED expenditure limit for the year (enter amount D2, E2, or F2, whichever applies) . . . . . **410** ______

* Amount D2 or E2 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less*	420		x	35 %	=	G2
Line 350 **minus** line 410 (if negative, enter "0")	430	921,352				

Amount from line 430 ______ x (Number of days in the tax year before 2014 ______ / Number of days in the tax year) x 20% = ______ c

Amount from line 430** 921,352 x (Number of days in the tax year after 2013 365 / Number of days in the tax year 365) x 15 % = 138,203 d

Subtotal (amount c **plus** amount d) .... 138,203 ▶ 138,203 H2

Line 410 **minus** line 350 (if negative, enter "0") .... ______ e

Capital expenditures (line 360 in Part 8) or amount e, whichever is less* .... **440** ______ x 35 % = ______ I2

Line 360 **minus** amount e (if negative, enter "0") .... **450** ______

Amount from line 450 ______ x (Number of days in the tax year before 2014 ______ / Number of days in the tax year) x 20% = ______ f

Amount from line 450** ______ x (Number of days in the tax year after 2013 365 / Number of days in the tax year 365) x 15 % = ______ g

Subtotal (amount f **plus** amount g) .... ______ ▶ ______ J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) ..... ______

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC*** .... **460** ______ x 35 % = ______ h

Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred before 2015 .... **480** ______ x 20 % = ______ i

Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred after 2014 ..... **490** ______ x 15 % = ______ j

Subtotal (**add** amounts h to j) ______ ▶ ______ K2

Current-year SR&ED ITC (total of amounts G2 to K2; enter on line 540 in Part 12) 138,203 L2

* For corporations that are not CCPCs, enter "0" for amounts G2 and I2.

** For tax years that end after 2013, the general SR&ED ITC rate is reduced from 20% to 15%, except that, for 2014 tax years that start **before** 2014, the reduction is pro-rated based on the number of days in the tax year that are **after** 2013. For tax years that have a start date **after** 2013, **multiply** the amount by 15%.

*** If you were a Canadian-controlled private corporation (CCPC), this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

Description	Line	Amount		Line	Amount	Code
ITC at the end of the previous tax year					1,492,873	M2
Credit deemed as a remittance of co-op corporations	510					
Credit expired	515					
Subtotal (line 510 **plus** line 515)			▶			N2
ITC at the beginning of the tax year (amount M2 **minus** amount N2)				520	1,492,873	
Credit transferred on an amalgamation or the wind-up of a subsidiary	530					
Total current-year credit (from amount L2 in Part 11)	540	138,203				
Credit allocated from a partnership	550					
Subtotal (total of lines 530 to 550)		138,203	▶		138,203	O2
Total credit available (line 520 **plus** amount O2)					1,631,076	P2
Credit deducted from Part I tax	560	1,631,076				
Credit carried back to previous years (amount S2 in Part 13)			k			
Credit transferred to offset Part VII tax liability	580					
Subtotal (total of line 560, amount k, and line 580)		1,631,076	▶		1,631,076	Q2
Credit balance before refund (amount P2 **minus** amount Q2)						R2
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)				610		
ITC closing balance on SR&ED (amount R2 **minus** line 610)				620		

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day		Line	Amount	Code
1st previous tax year				Credit to be applied	911		
2nd previous tax year				Credit to be applied	912		
3rd previous tax year				Credit to be applied	913		
				Total of lines 911 to 913 Enter at amount k in Part 12.			S2

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) . . . . . ______ I

Refundable credits (amount I or amount R2 in Part 12, whichever is less)* . . . . . ______ T2

Amount T2 or amount G2 in Part 11, whichever is less . . . . . ______ U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") . . . . . ______ V2

Amount V2 **multiplied** by 40 % . . . . . ______ W2

Amount U2 . . . . . ______ X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) . . . . . ______ Y2

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (amount R2 in Part 12) . . . . . ______ Z2

Amount Z2 or amount G2 in Part 11, whichever is less . . . . . ______ AA2

Net amount (amount Z2 **minus** amount AA2; if negative, enter "0") . . . . . ______ BB2

Amount BB2 or amount I2 in Part 11, whichever is less . . . . . ______ CC2

Amount CC2 **multiplied** by 40 % . . . . . ______ DD2

Amount AA2 . . . . . ______ EE2

Refund of ITC (amount DD2 **plus** amount EE2) . . . . . ______ FF2

Enter FF2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less

Subtotal Enter at amount C3 in Part 17. A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (total of column F) Enter at amount D3 in Part 17. B3

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760** ____
Enter at amount E3 in Part 17.

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16		C3
Recaptured ITC from calculation 2, amount B3 in Part 16		D3
Recaptured ITC from calculation 3, line 760 in Part 16		E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3) Enter at amount A8 in Part 29.		F3

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that you incurred in the tax year (**before** January 1, 2014) for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		
Geological, geophysical, or geochemical surveys	811		
Drilling by rotary, diamond, percussion, or other methods	812		
Trenching, digging test pits, and preliminary sampling	813		

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		
Sinking a mine shaft, constructing an adit, or other underground entry	821		

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Total of column 826	►		A4
Total pre-production mining expenditures (total of lines 810 to 821 and amount A4)	830		
Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to on line 830 above	832		
Excess (line 830 **minus** line 832) (if negative, enter "0")			B4
Repayments of government and non-government assistance	835		
Pre-production mining expenditures (amount B4 **plus** line 835)			C4

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year D4

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal (line 841 **plus** line 845) ► E4

ITC at the beginning of the tax year (amount D4 **minus** amount E4) 850

Credit transferred on an amalgamation or the wind-up of a subsidiary 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part from amount C4 in Part 18) . . 870 x 10 % = m

Pre-production mining exploration expenditures** incurred in 2013 (applicable part from amount C4 in Part 18) . . 872 x 5 % = n

Pre-production mining development expenditures incurred in 2014 (applicable part from amount C4 in Part 18) . . 874 x 7 % = o

Pre-production mining development expenditures incurred in 2015 (applicable part from amount C4 in Part 18) . . 876 x 4 % = p

Current year credit (total of amounts m to p) 880 ► F4

Total credit available (total of lines 850, 860, and amount F4) G4

Credit deducted from Part I tax 885

Credit carried back to previous years (amount I4 in Part 20) . . . . . . q

Subtotal (line 885 **plus** amount q) ► H4

ITC closing balance from pre-production mining expenditures (amount G4 **minus** amount H4) 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

** Also include pre-production mining development expenditures incurred in 2015 if the expense is described in subparagraph (a)(ii) of the definition **pre-production mining expenditure** in subsection 127(9) of the Act because of paragraph (g.4) of the definition **Canadian exploration expense** in subsection 66.1(6) of the Act.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year Month Day		
1st previous tax year		. . . . . . Credit to be applied	921
2nd previous tax year		. . . . . . Credit to be applied	922
3rd previous tax year		. . . . . . Credit to be applied	923

Total of lines 921 to 923
Enter at amount q in Part 19. I4

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	[redacted]	309A	568	57	57
2.	[redacted]	309A	1,580	158	158

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
3.	[redacted]	309A	2,789	279	279
4.		309A	4,436	444	444
5.		309A	4,645	465	465
6.		309A	4,922	492	492
7.		434A	5,166	517	517
8.		434A	5,400	540	540
9.		434A	5,676	568	568
10.		310T	5,761	576	576
11.		309A	5,795	580	580
12.		310T	5,896	590	590
13.		309A	6,227	623	623
14.		434A	6,270	627	627
15.		309A	6,386	639	639
16.		309A	6,452	645	645
17.		434A	6,493	649	649
18.		434A	6,633	663	663
19.		309A	6,923	692	692
20.		434A	7,026	703	703
21.		310T	7,094	709	709
22.		434A	7,099	710	710
23.		434A	7,102	710	710
24.		309A	7,259	726	726
25.		434A	7,273	727	727
26.		434A	7,474	747	747
27.		434A	7,562	756	756
28.		309A	8,049	805	805
29.		434A	8,084	808	808
30.		434A	8,235	824	824
31.		434A	8,397	840	840
32.		434A	8,409	841	841
33.		309A	8,412	841	841
34.		434A	8,589	859	859
35.		434A	9,057	906	906
36.		309A	10,018	1,002	1,002
37.		309A	12,709	1,271	1,271
38.		309A	15,842	1,584	1,584
39.		434A	16,054	1,605	1,605
40.		434A	16,983	1,698	1,698
41.		434A	17,168	1,717	1,717
42.		434A	17,514	1,751	1,751
43.		434A	17,971	1,797	1,797
44.		434A	18,296	1,830	1,830
45.		309A	18,461	1,846	1,846
46.		434A	18,774	1,877	1,877
47.		309A	18,821	1,882	1,882
48.		434A	19,334	1,933	1,933
49.		434A	19,561	1,956	1,956
50.		434A	19,568	1,957	1,957
51.		309A	19,694	1,969	1,969
52.		434A	19,880	1,988	1,988
53.		309A	19,892	1,989	1,989
54.		309A	42,626	4,263	2,000
55.		309A	37,536	3,754	2,000
56.		403A	42,894	4,289	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
57.	[redacted]	434A	37,622	3,762	2,000
58.		434A	20,310	2,031	2,000
59.		309A	42,838	4,284	2,000
60.		403A	63,666	6,367	2,000
61.		309A	32,365	3,237	2,000
62.		309A	37,882	3,788	2,000
63.		434A	54,839	5,484	2,000
64.		434A	33,863	3,386	2,000
65.		434A	48,595	4,860	2,000
66.		434A	68,745	6,875	2,000
67.		434A	74,235	7,424	2,000
68.		434A	30,861	3,086	2,000
69.		434A	37,919	3,792	2,000
70.		434A	60,079	6,008	2,000
71.		309A	40,916	4,092	2,000
72.		309A	38,917	3,892	2,000
73.		434A	22,098	2,210	2,000
74.		434A	55,671	5,567	2,000
75.		434A	63,396	6,340	2,000
76.		434A	92,962	9,296	2,000
77.		434A	43,563	4,356	2,000
78.		309A	60,154	6,015	2,000
79.		434A	37,970	3,797	2,000
80.		309A	30,977	3,098	2,000
81.		434A	68,629	6,863	2,000
82.		434A	28,789	2,879	2,000
83.		434A	44,872	4,487	2,000
84.		309A	23,284	2,328	2,000
85.		309A	39,648	3,965	2,000
86.		434A	31,366	3,137	2,000
87.		434A	56,932	5,693	2,000
88.		434A	66,475	6,648	2,000
89.		434A	25,223	2,522	2,000
90.		434A	76,449	7,645	2,000
91.		434A	30,494	3,049	2,000
92.		434A	66,986	6,699	2,000
93.		309A	48,699	4,870	2,000
94.		434A	66,479	6,648	2,000
95.		434A	63,399	6,340	2,000
96.		434A	40,466	4,047	2,000
97.		309A	24,218	2,422	2,000
98.		434A	36,067	3,607	2,000
99.		309A	83,449	8,345	2,000
100		434A	52,827	5,283	2,000
101		434A	55,644	5,564	2,000
102		309A	48,375	4,838	2,000
103		434A	41,971	4,197	2,000
104		434A	67,300	6,730	2,000
105		434A	55,146	5,515	2,000
106		309A	24,355	2,436	2,000
107		309A	25,410	2,541	2,000
108		434A	29,465	2,947	2,000
109		434A	74,615	7,462	2,000
110		434A	41,161	4,116	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
111	[redacted]	434A	70,496	7,050	2,000
112	[redacted]	434A	67,932	6,793	2,000
113	[redacted]	434A	25,780	2,578	2,000
114	[redacted]	309A	61,288	6,129	2,000
115	[redacted]	434A	59,551	5,955	2,000
116	[redacted]	434A	52,986	5,299	2,000
117	[redacted]	434A	32,039	3,204	2,000
118	[redacted]	434A	52,912	5,291	2,000
119	[redacted]	309A	31,368	3,137	2,000
120	[redacted]	434A	53,280	5,328	2,000
121	[redacted]	434A	72,447	7,245	2,000
122	[redacted]	434A	75,416	7,542	2,000
123	[redacted]	434A	23,646	2,365	2,000
124	[redacted]	434A	20,904	2,090	2,000
125	[redacted]	309A	45,717	4,572	2,000
126	[redacted]	434A	59,086	5,909	2,000
127	[redacted]	434A	24,251	2,425	2,000
128	[redacted]	434A	78,182	7,818	2,000
129	[redacted]	434A	27,500	2,750	2,000
130	[redacted]	434A	67,751	6,775	2,000
131	[redacted]	309A	27,953	2,795	2,000
132	[redacted]	309A	39,425	3,943	2,000
133	[redacted]	434A	71,889	7,189	2,000
134	[redacted]	309A	33,621	3,362	2,000
135	[redacted]	434A	26,838	2,684	2,000
136	[redacted]	434A	70,285	7,029	2,000
137	[redacted]	434A	33,601	3,360	2,000
138	[redacted]	434A	53,086	5,309	2,000
139	[redacted]	434A	57,797	5,780	2,000
140	[redacted]	434A	65,848	6,585	2,000
141	[redacted]	309A	42,067	4,207	2,000
142	[redacted]	434A	75,750	7,575	2,000
143	[redacted]	434A	72,286	7,229	2,000
144	[redacted]	434A	37,818	3,782	2,000
145	[redacted]	434A	28,168	2,817	2,000
146	[redacted]	309A	26,188	2,619	2,000
147	[redacted]	434A	38,949	3,895	2,000
148	[redacted]	434A	38,492	3,849	2,000
149	[redacted]	434A	80,073	8,007	2,000
150	[redacted]	434A	49,414	4,941	2,000
151	[redacted]	434A	32,969	3,297	2,000
152	[redacted]	434A	73,333	7,333	2,000
153	[redacted]	434A	32,051	3,205	2,000
154	[redacted]	434A	33,059	3,306	2,000
155	[redacted]	434A	27,150	2,715	2,000
156	[redacted]	434A	42,199	4,220	2,000
157	[redacted]	434A	27,783	2,778	2,000
158	[redacted]	434A	28,947	2,895	2,000
159	[redacted]	434A	53,506	5,351	2,000
160	[redacted]	434A	58,131	5,813	2,000
161	[redacted]	434A	63,549	6,355	2,000
162	[redacted]	309A	65,449	6,545	2,000
163	[redacted]	434A	86,135	8,614	2,000
164	[redacted]	309A	36,910	3,691	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
165	[redacted]	309A	62,083	6,208	2,000
166		434A	61,407	6,141	2,000
167		434A	67,312	6,731	2,000
168		434A	42,830	4,283	2,000
169		434A	89,267	8,927	2,000
170		434A	82,203	8,220	2,000
171		434A	61,741	6,174	2,000
172		434A	67,758	6,776	2,000
173		434A	41,169	4,117	2,000
174		434A	50,185	5,019	2,000
175		434A	38,061	3,806	2,000
176		310T	69,900	6,990	2,000
177		434A	47,051	4,705	2,000
178		434A	57,054	5,705	2,000
179		434A	65,469	6,547	2,000
180		309A	45,918	4,592	2,000
181		434A	68,288	6,829	2,000
182		434A	69,402	6,940	2,000
183		434A	77,398	7,740	2,000
184		309A	36,040	3,604	2,000
185		309A	38,270	3,827	2,000
186		434A	55,383	5,538	2,000
187		434A	66,569	6,657	2,000
188		434A	58,175	5,818	2,000
189		434A	81,720	8,172	2,000
190		309A	54,517	5,452	2,000
191		434A	57,384	5,738	2,000
192		434A	80,855	8,086	2,000
193		309A	60,731	6,073	2,000
194		434A	81,392	8,139	2,000
195		434A	63,083	6,308	2,000
196		434A	34,166	3,417	2,000
197		434A	29,794	2,979	2,000
198		434A	69,893	6,989	2,000
199		434A	62,361	6,236	2,000
200		434A	68,370	6,837	2,000
201		434A	69,510	6,951	2,000
202		434A	35,085	3,509	2,000
203		310T	72,735	7,274	2,000
204		434A	24,612	2,461	2,000
205		434A	68,130	6,813	2,000
206		434A	66,669	6,667	2,000
207		309A	45,369	4,537	2,000
208		310T	58,713	5,871	2,000
209		434A	31,980	3,198	2,000
210		434A	66,812	6,681	2,000
211		434A	44,681	4,468	2,000
212		309A	22,914	2,291	2,000
213		309A	53,344	5,334	2,000
214		309A	54,231	5,423	2,000
215		309A	21,116	2,112	2,000
216		434A	50,936	5,094	2,000
217		434A	52,987	5,299	2,000
218		434A	32,208	3,221	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
219	[redacted]	434A	65,481	6,548	2,000
220		309A	46,124	4,612	2,000
221		434A	25,388	2,539	2,000
222		434A	72,963	7,296	2,000
223		434A	56,985	5,699	2,000
224		434A	66,051	6,605	2,000
225		309A	24,509	2,451	2,000
226		434A	65,057	6,506	2,000
227		434A	76,426	7,643	2,000
228		434A	42,019	4,202	2,000
229		434A	71,957	7,196	2,000
230		434A	60,105	6,011	2,000
231		434A	47,643	4,764	2,000
232		434A	42,909	4,291	2,000
233		309A	48,113	4,811	2,000
234		434A	37,205	3,721	2,000
235		434A	71,771	7,177	2,000
236		309A	26,176	2,618	2,000
237		434A	56,181	5,618	2,000
238		434A	26,907	2,691	2,000
239		310T	48,549	4,855	2,000
240		309A	25,339	2,534	2,000
241		434A	61,245	6,125	2,000
242		434A	42,557	4,256	2,000
243		309A	47,136	4,714	2,000
244		434A	62,861	6,286	2,000
245		309A	46,560	4,656	2,000
246		434A	34,343	3,434	2,000
247		309A	20,766	2,077	2,000
248		434A	58,987	5,899	2,000
249		434A	57,935	5,794	2,000
250		434A	62,019	6,202	2,000
251		434A	91,565	9,157	2,000
252		309A	30,659	3,066	2,000
253		434A	57,058	5,706	2,000
254		434A	64,898	6,490	2,000
255		309A	34,515	3,452	2,000
256		434A	71,687	7,169	2,000
257		309A	28,544	2,854	2,000
258		434A	70,854	7,085	2,000
259		434A	38,712	3,871	2,000
260		434A	59,901	5,990	2,000
261		434A	25,677	2,568	2,000
262		434A	88,168	8,817	2,000
263		309A	42,714	4,271	2,000
264		434A	47,059	4,706	2,000
265		434A	67,209	6,721	2,000
266		434A	40,909	4,091	2,000
267		434A	61,966	6,197	2,000
268		434A	37,308	3,731	2,000
269		434A	48,901	4,890	2,000
270		434A	49,541	4,954	2,000
271		434A	36,180	3,618	2,000
272		434A	47,058	4,706	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
273	[redacted]	309A	22,625	2,263	2,000
274	[redacted]	434A	27,337	2,734	2,000
275	[redacted]	434A	53,378	5,338	2,000
276	[redacted]	434A	43,043	4,304	2,000
277	[redacted]	434A	67,461	6,746	2,000
278	[redacted]	434A	70,052	7,005	2,000
279	[redacted]	309A	31,126	3,113	2,000
280	[redacted]	434A	76,902	7,690	2,000
281	[redacted]	434A	62,721	6,272	2,000
282	[redacted]	434A	74,453	7,445	2,000
283	[redacted]	309A	42,534	4,253	2,000
284	[redacted]	309A	50,013	5,001	2,000
285	[redacted]	434A	30,734	3,073	2,000
286	[redacted]	434A	73,395	7,340	2,000
287	[redacted]	434A	68,027	6,803	2,000
288	[redacted]	434A	50,809	5,081	2,000
289	[redacted]	434A	37,438	3,744	2,000
290	[redacted]	434A	61,874	6,187	2,000
291	[redacted]	434A	22,373	2,237	2,000
292	[redacted]	434A	82,707	8,271	2,000
293	[redacted]	434A	36,053	3,605	2,000
294	[redacted]	309A	60,579	6,058	2,000
295	[redacted]	434A	72,882	7,288	2,000
296	[redacted]	434A	65,604	6,560	2,000
297	[redacted]	434A	74,067	7,407	2,000
298	[redacted]	434A	30,248	3,025	2,000
299	[redacted]	434A	25,413	2,541	2,000
300	[redacted]	434A	70,480	7,048	2,000
301	[redacted]	309A	55,913	5,591	2,000
302	[redacted]	434A	40,959	4,096	2,000
303	[redacted]	434A	53,722	5,372	2,000
304	[redacted]	434A	40,606	4,061	2,000
305	[redacted]	434A	38,055	3,806	2,000
306	[redacted]	309A	22,772	2,277	2,000
307	[redacted]	434A	53,641	5,364	2,000
308	[redacted]	434A	73,864	7,386	2,000
309	[redacted]	434A	23,164	2,316	2,000
310	[redacted]	434A	26,498	2,650	2,000
311	[redacted]	434A	41,431	4,143	2,000
312	[redacted]	309A	49,098	4,910	2,000
313	[redacted]	434A	53,769	5,377	2,000
314	[redacted]	434A	35,876	3,588	2,000
315	[redacted]	434A	43,085	4,309	2,000
316	[redacted]	434A	65,917	6,592	2,000
317	[redacted]	309A	28,769	2,877	2,000
318	[redacted]	434A	38,316	3,832	2,000
319	[redacted]	434A	62,595	6,260	2,000
320	[redacted]	434A	51,904	5,190	2,000
321	[redacted]	434A	79,991	7,999	2,000
322	[redacted]	434A	56,303	5,630	2,000
323	[redacted]	309A	27,490	2,749	2,000
324	[redacted]	309A	36,019	3,602	2,000
325	[redacted]	434A	37,050	3,705	2,000
326	[redacted]	434A	42,377	4,238	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
327	[redacted]	309A	74,298	7,430	2,000
328	[redacted]	434A	36,735	3,674	2,000
329	[redacted]	434A	51,831	5,183	2,000
330	[redacted]	309A	25,815	2,582	2,000
331	[redacted]	434A	60,890	6,089	2,000
332	[redacted]	434A	36,970	3,697	2,000
333	[redacted]	434A	24,251	2,425	2,000
334	[redacted]	309A	45,601	4,560	2,000
335	[redacted]	309A	33,239	3,324	2,000
336	[redacted]	309A	22,853	2,285	2,000
337	[redacted]	434A	34,707	3,471	2,000
338	[redacted]	434A	34,410	3,441	2,000
339	[redacted]	434A	30,591	3,059	2,000
340	[redacted]	434A	54,589	5,459	2,000
341	[redacted]	434A	73,839	7,384	2,000
342	[redacted]	434A	35,071	3,507	2,000
343	[redacted]	434A	22,202	2,220	2,000
344	[redacted]	434A	62,343	6,234	2,000
345	[redacted]	434A	27,807	2,781	2,000
346	[redacted]	309A	22,714	2,271	2,000
347	[redacted]	434A	55,640	5,564	2,000
348	[redacted]	434A	31,659	3,166	2,000
349	[redacted]	434A	38,473	3,847	2,000
350	[redacted]	434A	57,535	5,754	2,000
351	[redacted]	403A	42,465	4,247	2,000
352	[redacted]	434A	72,138	7,214	2,000
353	[redacted]	434A	72,609	7,261	2,000
354	[redacted]	434A	66,762	6,676	2,000
355	[redacted]	434A	42,769	4,277	2,000
356	[redacted]	434A	71,229	7,123	2,000
357	[redacted]	434A	31,309	3,131	2,000
358	[redacted]	434A	60,643	6,064	2,000
359	[redacted]	434A	37,179	3,718	2,000
360	[redacted]	434A	20,732	2,073	2,000
361	[redacted]	434A	67,563	6,756	2,000
362	[redacted]	309A	53,843	5,384	2,000
363	[redacted]	434A	70,318	7,032	2,000
364	[redacted]	434A	41,182	4,118	2,000
365	[redacted]	434A	76,359	7,636	2,000
366	[redacted]	309A	29,812	2,981	2,000
367	[redacted]	309A	45,023	4,502	2,000
368	[redacted]	434A	50,395	5,040	2,000
369	[redacted]	434A	61,986	6,199	2,000
370	[redacted]	434A	58,049	5,805	2,000
371	[redacted]	434A	66,249	6,625	2,000
372	[redacted]	309A	30,817	3,082	2,000
373	[redacted]	434A	64,557	6,456	2,000
374	[redacted]	434A	26,609	2,661	2,000
375	[redacted]	434A	62,200	6,220	2,000
376	[redacted]	309A	50,053	5,005	2,000
377	[redacted]	434A	79,273	7,927	2,000
378	[redacted]	309A	23,980	2,398	2,000
379	[redacted]	309A	44,032	4,403	2,000
380	[redacted]	434A	25,572	2,557	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
381	[redacted]	309A	42,120	4,212	2,000
382	[redacted]	434A	74,216	7,422	2,000
383	[redacted]	434A	36,960	3,696	2,000
384	[redacted]	309A	62,953	6,295	2,000
385	[redacted]	434A	20,384	2,038	2,000
386	[redacted]	403A	49,617	4,962	2,000
387	[redacted]	434A	66,013	6,601	2,000
388	[redacted]	434A	22,683	2,268	2,000
389	[redacted]	309A	36,970	3,697	2,000
390	[redacted]	434A	35,328	3,533	2,000
391	[redacted]	434A	65,851	6,585	2,000
392	[redacted]	434A	27,760	2,776	2,000
393	[redacted]	309A	30,172	3,017	2,000
394	[redacted]	434A	76,219	7,622	2,000
395	[redacted]	434A	61,432	6,143	2,000
396	[redacted]	309A	69,639	6,964	2,000
397	[redacted]	434A	29,361	2,936	2,000
398	[redacted]	434A	63,661	6,366	2,000
399	[redacted]	309A	30,093	3,009	2,000
400	[redacted]	434A	35,216	3,522	2,000
401	[redacted]	434A	66,123	6,612	2,000
402	[redacted]	434A	45,900	4,590	2,000
403	[redacted]	309A	55,604	5,560	2,000
404	[redacted]	434A	60,261	6,026	2,000
405	[redacted]	434A	55,618	5,562	2,000
406	[redacted]	309A	36,160	3,616	2,000
407	[redacted]	434A	33,427	3,343	2,000
408	[redacted]	434A	45,717	4,572	2,000
409	[redacted]	309A	29,075	2,908	2,000
410	[redacted]	434A	29,752	2,975	2,000
411	[redacted]	434A	72,637	7,264	2,000
412	[redacted]	434A	67,537	6,754	2,000
413	[redacted]	434A	64,136	6,414	2,000
414	[redacted]	434A	34,332	3,433	2,000
415	[redacted]	434A	56,954	5,695	2,000
416	[redacted]	434A	58,428	5,843	2,000
417	[redacted]	434A	50,536	5,054	2,000
418	[redacted]	309A	28,536	2,854	2,000
419	[redacted]	434A	85,343	8,534	2,000
420	[redacted]	434A	78,452	7,845	2,000
421	[redacted]	434A	26,730	2,673	2,000
422	[redacted]	434A	30,901	3,090	2,000
423	[redacted]	309A	49,548	4,955	2,000
424	[redacted]	434A	64,842	6,484	2,000
425	[redacted]	309A	38,297	3,830	2,000
426	[redacted]	434A	66,987	6,699	2,000
427	[redacted]	434A	51,402	5,140	2,000
428	[redacted]	434A	72,352	7,235	2,000
429	[redacted]	309A	26,014	2,601	2,000
430	[redacted]	434A	53,226	5,323	2,000
431	[redacted]	434A	32,771	3,277	2,000
432	[redacted]	434A	63,142	6,314	2,000
433	[redacted]	434A	45,898	4,590	2,000
434	[redacted]	309A	29,323	2,932	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
435	[redacted]	434A	34,621	3,462	2,000
436	[redacted]	434A	26,930	2,693	2,000
437	[redacted]	434A	63,634	6,363	2,000
438	[redacted]	434A	43,226	4,323	2,000
439	[redacted]	434A	50,917	5,092	2,000
440	[redacted]	434A	43,910	4,391	2,000
441	[redacted]	309A	45,802	4,580	2,000
442	[redacted]	309A	27,461	2,746	2,000
443	[redacted]	309A	51,149	5,115	2,000
444	[redacted]	434A	21,332	2,133	2,000
445	[redacted]	434A	38,135	3,814	2,000
446	[redacted]	434A	55,403	5,540	2,000
447	[redacted]	434A	38,078	3,808	2,000
448	[redacted]	434A	59,029	5,903	2,000
449	[redacted]	434A	32,826	3,283	2,000
450	[redacted]	310T	50,016	5,002	2,000
451	[redacted]	434A	71,667	7,167	2,000
452	[redacted]	434A	66,125	6,613	2,000
453	[redacted]	434A	69,962	6,996	2,000
454	[redacted]	434A	62,722	6,272	2,000
455	[redacted]	434A	38,247	3,825	2,000
456	[redacted]	434A	21,652	2,165	2,000
457	[redacted]	434A	69,167	6,917	2,000
458	[redacted]	434A	69,003	6,900	2,000
459	[redacted]	434A	31,380	3,138	2,000
460	[redacted]	434A	57,013	5,701	2,000
461	[redacted]	434A	44,813	4,481	2,000
462	[redacted]	309A	28,430	2,843	2,000
463	[redacted]	309A	27,950	2,795	2,000
464	[redacted]	434A	39,297	3,930	2,000
465	[redacted]	310T	53,654	5,365	2,000
466	[redacted]	434A	33,224	3,322	2,000
467	[redacted]	434A	73,918	7,392	2,000
468	[redacted]	434A	72,107	7,211	2,000
469	[redacted]	309A	22,307	2,231	2,000
470	[redacted]	434A	70,953	7,095	2,000
471	[redacted]	309A	38,565	3,857	2,000
472	[redacted]	434A	62,550	6,255	2,000
473	[redacted]	309A	57,926	5,793	2,000
				Total current-year credit (total of column E) Enter on line 640 in Part 22.	893,968 A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			1,472,589	B5
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal (line 612 **plus** line 615)		▶		C5
ITC at the beginning of the tax year (amount B5 **minus** amount C5)	625		1,472,589	
Credit transferred on an amalgamation or the wind-up of a subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (amount A5 in Part 21)	640	893,968		
Credit allocated from a partnership	655			
Subtotal (total of lines 630 to 655)		893,968 ▶	893,968	D5
Total credit available (line 625 **plus** amount D5)			2,366,557	E5
Credit deducted from Part I tax	660	2,366,557		
Credit carried back to previous years (amount G5 in Part 23)		r		
Subtotal (line 660 **plus** amount r)		2,366,557 ▶	2,366,557	F5
ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5)	690			

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total of lines 931 to 933 Enter at amount r in Part 22.		G5

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred after March 18, 2007 and before March 22, 2017* to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures.

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695) **715** ____

Specified child care start-up expenditures from the current tax year . . . . . **705** ____

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ____ A6

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . . **725** ____

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . . ____ B6

Repayments by the corporation of government and non-government assistance . . . . . **735** ____

Total eligible expenditures for child care spaces (amount B6 **plus** line 735) . . . . . **745** ____

* If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 24) . . . . . ____ x 25 % = ____ C6

Number of child care spaces . . . . . **755** ____ x $ 10,000 = ____ D6

ITC from child care spaces expenditures (amount C6 or D6, whichever is less) . . . . . ____ E6

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F6
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			►	G6
ITC at the beginning of the tax year (amount F6 **minus** amount G6)			775	
Credit transferred on an amalgamation or the wind-up of a subsidiary	777			
Total current-year credit (amount E6 in Part 25)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			►	H6
Total credit available (line 775 **plus** amount H6)				I6
Credit deducted from Part I tax	785			
Credit carried back to previous years (amount K6 in Part 27)			s	
Subtotal (line 785 **plus** amount s)			►	J6
ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6)			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2017-12-31	Credit to be applied	941	
2nd previous tax year	2016-12-31	Credit to be applied	942	
3rd previous tax year	2015-12-31	Credit to be applied	943	

Total of lines 941 to 943 K6
Enter at amount s in Part 26.

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a))			792	
In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:				
The amount that can reasonably be considered to have been included in the original ITC	795			
25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property	797			
Amount from line 795 or line 797, whichever is less				A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC	799		
Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) Enter at amount B8 in Part 29.			B7

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount F3 in Part 17)		A8
Recaptured child care spaces ITC (amount B7 in Part 28)		B8
Total recapture of investment tax credit (amount A8 **plus** amount B8) Enter on line 602 of the T2 return.		C8

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5)		D8
ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12)	1,631,076	E8
ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 19)		F8
ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 22)	2,366,557	G8
ITC from child care space expenditures deducted from Part I tax (line 785 in Part 26)		H8
Total ITC deducted from Part I tax (total of amounts D8 to H8) Enter on line 652 of the T2 return.	3,997,633	I8

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
893,968	893,968			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2017-12-31	890,686		890,686	
2016-12-31	580,013		580,013	
2015-12-31	1,890		1,890	
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				*
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2000-12-31				*
Total	1,472,589		1,472,589	

B+C+D+G **Total ITC utilized** 2,366,557

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 99 Cur. or cap. R&D for ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	138,203	138,203			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2017-12-31	235,603		235,603	
2016-12-31	1,043,571		1,043,571	
2015-12-31	213,699		213,699	
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				*
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2000-12-31				*
Total	1,492,873		1,492,873	

B+C+D+G **Total ITC utilized** 1,631,076

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

	Line	Amount		
Reserves that have not been deducted in calculating income for the year under Part I	101	1,770,070,786		
Capital stock (or members' contributions if incorporated without share capital)	103	4,144,000,000		
Retained earnings	104	5,069,402,009		
Contributed surplus	105	5,000,000		
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	11,707,598,337		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		22,696,071,132	22,696,071,132	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
- a) those lines applied to partnerships in the same manner that they apply to corporations, and
- b) those amounts were computed without reference to amounts owing by the partnership
  - (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
  - (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			22,696,071,132 A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121	949,000,000	
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)		949,000,000 ▶	949,000,000 B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		21,747,071,132

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	3,490,094
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	3,490,094

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		21,747,071,132 C
Deduct: Investment allowance for the year (line 490)		3,490,094 D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	21,743,581,038

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 21,743,581,038 x Taxable income earned in Canada **610** 26,657,334 / Taxable income 26,657,334 = **Taxable capital employed in Canada** **690** 21,743,581,038

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ______

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ______

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ______

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ______

Total deductions (**add** lines 711, 712, and 713) ______ ► ______ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ______

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.225%)		I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Schedule 33/CT23 - Supplementary Schedule Line 402

Description	Operator (Note)	Amount	
Prepaid insurance (a/c 277180)		2,145,205	00
Deposit -Bnft Provider (a/c 277290)	+	1,344,889	00
	+		
	Total	3,490,094	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in calculating income for th

Description	Operator (Note)	Amount	
Schedule 13 Reserves Ending		1,770,070,786	00
	+		
	Total	1,770,070,786	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount	
LT Debt Payable within a year (FS)		728,000,000	00
Primary Debt (FS)	+	9,486,000,000	00
Intercompany Demand Facility (FS)	+	1,447,000,000	00
Customer Deposits (GL 390000/391010/392000/392010)	+	40,305,704	00
Banked Vacation (GL 362100)	+	6,292,633	00
	+		
	Total	11707598337	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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SCHEDULE 44

NON-ARM'S LENGTH TRANSACTIONS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

Where all or almost all (90% or more) of the assets of a non-arm's length corporation have been received in the tax year, and subsection 85(1) or (2) or 142.7(3) of the federal *Income Tax Act* applied for the disposition of any of the property, report the following details:

	Transferor corporation's name 100	Transferor corporation's Business Number 200	Date of transfer (YYYY/MM/DD) 300
1	Hydro One Inc.	86999 4731 RC0001	2018-12-10

T2 SCH 44 E (07)

Canada

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Schedule 54

Low Rate Income Pool (LRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

On: 2018-12-31

- Use this schedule to calculate the balance of the low rate income pool (LRIP) at any time in the tax year if you are a corporation resident in Canada that is:
  - a corporation **other** than a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC); or
  - a corporation that elected under subsection 89(11) not to be a CCPC.
- When an eligible dividend was paid or there was a change in the LRIP balance in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Did the corporation elect not to be a CCPC under subsection 89(11) ITA for the current year or a prior year or did it revoke this election in the current year*? . . . . . [ ] Yes [X] No

* If the corporation revoked its election in the current year when filing Form T2002, this election will still be valid for the current year, but will cease to apply as of the end of the year.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

Change in the type of corporation

1. Was the corporation a CCPC during its preceding taxation year? . . . . . [ ] Yes [X] No
2. Corporations that ceased to be a CCPC or a DIC . . . . . [ ] Yes [X] No
   If the answer to question 2 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

3. Corporations that were formed as a result of an amalgamation . . . . . [ ] Yes [X] No
   If the answer to question 3 is yes, answer questions 4 and 5. If the answer is no, go to question 6.
4. Was one or several of the predecessor corporations a CCPC or a DIC during the taxation year that ended immediately before the amalgamation? . . . . . [ ] Yes [ ] No
   If the answer to question 4 is yes, complete Part 5.
5. Was one or several of the predecessor corporations neither a CCPC nor a DIC? . . . . . [ ] Yes [ ] No
   If the answer to question 5 is yes, complete Part 5 (line R).

Winding-up

6. Corporations that wound-up a subsidiary . . . . . [ ] Yes [X] No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to Part 1.
7. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . [ ] Yes [X] No
   If the answer to question 7 is yes, complete Part 6.
8. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . [X] Yes [ ] No
   If the answer to question 8 is yes, complete Part 6 (line R).

Part 1 – Low rate income pool (LRIP)

LRIP at the end of the immediately previous tax year . . . . . **100** ______

Income for the credit union deduction (amount 2E in Part 2 of Schedule 17 of the previous year if the corporation was **not** a CCPC in the previous tax year for the purpose of paying eligible dividends, otherwise enter "0") . . . . . **120** ______

Aggregate investment income of a corporation that has elected under subsection 89(11) not to be a CCPC (line 440 of the T2 return of the previous tax year) . . . . . **140** ______

Subtotal (line 120 **plus** 140) ______ x 80 % = **150** ______

Investment corporation deduction (line 620 of the T2 return of the previous tax year) . . . . . ______ x 4 = **160** ______

Subtotal (**add** lines 100, 150, and 160) **190** ______

T2 SCH54 E (17)

Canada

Part 2 – LRIP and excessive eligible dividend designations during the tax year

Complete this part if you paid an eligible dividend in the tax year.

	200 Date[1] (yyyy/mm/dd)	210 Total dividends[2] receivable in the year before the date on line 200 that are deductible under section 112	220 Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC[3]	230 Subtotal (**add** lines 190, 210, and 220)	240 Total dividends[4] payable in the year before the date on line 200	250 Total of excessive eligible dividend designations made before the date on line 200
1.	2018-02-20					
2.						

	260 LRIP as of the date on line 200 (line 230 **minus** the total of line 240 and line 250)	270 Total eligible dividends paid on the date on line 200	280 Excessive eligible dividend designation (lesser of lines 260 and 270)
1.		500,000	
2.			

Total excessive eligible dividend designations in the tax year (total of all amounts in column 280) ______ A
Enter amount A at amount G of Schedule 55.

1 Enter on line 200 each date where:
- an eligible dividend was paid in the year; or
- an adjustment was made as a result of an amalgamation or the wind-up of a subsidiary or on ceasing to be a CCPC (by an election or otherwise).

2 Taxable dividends from a corporation resident in Canada (other than eligible dividends).

3 Complete the worksheets in Parts 4 to 6 separately for each predecessor, each subsidiary involved in the wind-up, and when the corporation ceases to be a CCPC or DIC. Add up the adjustments for this date and enter on line 220.

4 Includes taxable dividends (other than an eligible dividend, a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1), or a dividend deductible under subsection 130.1(1))

Part 3 – LRIP closing balance

Amount from line 190 in Part 1 .... B

Dividends[5] receivable in the tax year that are deductible under section 112 (Amount on line 210 in the last row (last date) of the chart in Part 2) ....

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends receivable in the year that are deductible under section 112 (hereinafter: "dividends other than eligible dividends receivable") on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends receivable other than eligible dividends receivable. ....

Total dividends[5] receivable in the tax year that are deductible under section 112 .... **510**

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC[6] (Amount on line 220 in the last row (last date) of the chart in Part 2) ....

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC[6] if no eligible dividend has been paid in the tax year ....

Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC[6] **520**

Subtotal (line 510 **plus** line 520) ► C

Subtotal (amount B **plus** amount C) D

Total dividends[7] payable in the tax year (Amount on line 240 in the last row (last date) of the chart in Part 2) ...

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends payable in the year (hereinafter: "dividends other that eligible dividends payable") on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends paid other than eligible dividends paid. ....

Total dividends[7] payable in the tax year **540**

Total excessive eligible dividend designations in the tax year (amount A in Part 2) .... E

Subtotal (line 540 **plus** amount E) ► F

LRIP at the end of the tax year (amount D **minus** amount F) (if negative enter "0") **590**

5 Taxable dividends from a corporation resident in Canada (other than eligible dividends)

6 Complete the worksheets in Parts 4 to 6 separately for each predecessor, each subsidiary involved in the wind-up, and when the corporation ceases to be a CCPC or DIC.

7 Includes taxable dividends (other than an eligible dividend, a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1), or a dividend deductible under subsection 130.1(1))

Part 4 – Worksheet for adjustment when a corporation ceases to be a CCPC or DIC

Adjustment date . . . . ______

Complete this part if the corporation is neither a CCPC nor a DIC in this tax year but was a CCPC or a DIC in the previous tax year.

This adjustment to the LRIP can be made at any time in the tax year.

Keep a copy of this calculation for your records in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of the previous tax year . . . ______ 1

The corporation's cash on hand immediately before the end of the previous tax year . . . ______ 2

Total of subsection 111(1) losses that would have been deductible in computing the corporation's taxable income for the previous tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous tax year:

Non-capital losses . . . ______ 3
Net capital losses . . . ______ 4
Farm losses . . . ______ 5
Restricted farm losses . . . ______ 6
Limited partnership losses . . . ______ 7
Subtotal (**add** amounts 3 to 7) ______ ► ______ 8

Total of all amounts deducted under subsection 111(1) in computing the corporation's taxable income for the previous tax year:

Non-capital losses . . . ______ 9
Net capital losses . . . ______ 10
Farm losses . . . ______ 11
Restricted farm losses . . . ______ 12
Limited partnership losses . . . ______ 13
Subtotal (**add** amounts 9 to 13) ______ ► ______ 14

Unused and unexpired losses at the end of the corporation's previous tax year (amount 8 **minus** amount 14) (if negative, enter "0") . . . ______ ► ______ 15

Subtotal (**add** amounts 1, 2, and 15) ______ 16

All of the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous tax year . . . ______ 17

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous tax year . . . ______ 18

All of the corporation's reserves deducted in its previous tax year . . . ______ 19

Is the corporation a private corporation? . . . ☐ Yes ☒ No

The corporation's capital dividend account immediately before the end of its previous tax year if the corporation is **not** a private corporation in the current tax year . . . ______ 20

The corporation's general rate income pool (GRIP) at the end of its previous tax year . . . ______ 21

Eligible dividends paid in the previous tax year . . . ______ 22

Excessive eligible dividend designations made in the previous tax year . . . ______ 23

Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") . . . ______ ► ______ 24

Subtotal (amount 21 **minus** amount 24) ______ ► ______ 25

Subtotal (**add** amounts 17, 18, 19, 20, 25) ______ ► ______ 26

Adjustment for a corporation that ceases to be a CCPC or DIC (amount 16 **minus** amount 26) (if negative, enter "0") . . . ______ 27

Part 5 – Worksheet for adjustment when a corporation is formed as a result of an amalgamation

nb. 1

Adjustment date . . . . ____________

Complete this part if the corporation was formed as a result of an amalgamation or merger of two or more corporations, one or more of which is a taxable Canadian corporation. Complete a separate worksheet for **each** predecessor.

This adjustment to the LRIP can be made at any time in the tax year.

The last tax year was its tax year that ended immediately before the amalgamation.

Keep a copy of this calculation for your records, in case we ask to see it later.

For a predecessor corporation that was a CCPC or a DIC in its tax year that ended immediately before the amalgamation.

Cost amount to the predecessor of all property immediately before the end of its last tax year				1
The predecessor's cash on hand immediately before the end of its last tax year				2
Total of subsection 111(1) losses that would have been deductible in computing the predecessor's taxable income for its last tax year if the predecessor had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for its last tax year:				
Non-capital losses	3			
Net capital losses	4			
Farm losses	5			
Restricted farm losses	6			
Limited partnership losses	7			
Subtotal (**add** amounts 3 to 7)	►	8		
Total of all amounts deducted under subsection 111(1) in computing the predecessor's taxable income for its last tax year:				
Non-capital losses	9			
Net capital losses	10			
Farm losses	11			
Restricted farm losses	12			
Limited partnership losses	13			
Subtotal (**add** amounts 9 to 13)	►	14		
Unused and unexpired losses at the end of the predecessor's last tax year (amount 8 **minus** amount 14) (if negative, enter "0")			►	15
Subtotal (**add** amounts 1, 2, and 15)				16
All of the predecessor's debts and other obligations to pay that were outstanding immediately before the end of its last tax year		17		
Paid up capital of all the predecessor's issued and outstanding shares of capital stock immediately before the end of its last tax year		18		
All of the predecessor's reserves deducted in its last tax year		19		
The predecessor's capital dividend account immediately before the end of its last tax year if the corporation is **not** a private corporation in its first tax year		20		
The predecessor's general rate income pool (GRIP) at the end of its last tax year	21			
Eligible dividends paid in its last tax year . . . ____ 22				
Excessive eligible dividend designations made in its last tax year . . . ____ 23				
Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") ►	24			
Subtotal (amount 21 **minus** amount 24)	►	25		
Subtotal (**add** amounts 17, 18, 19, 20, 25)			►	26
Adjustment for a predecessor corporation that was a CCPC or a DIC in its last tax year (amount 16 **minus** amount 26) (if negative, enter "0")				27

For a predecessor corporation that was neither a CCPC nor a DIC in its tax year that ended immediately before the amalgamation

LRIP at the end of its last tax year . . . . ____________ 28

Adjustment for a predecessor corporation involved in an amalgamation (amount 27 **plus** amount 28) . . . . . . ____________ 29

Calculate amount 29 for **each** predecessor.

Part 6 – Worksheet for adjustment when a corporation has wound-up a subsidiary

nb. 1

Adjustment date . . . . ________

Complete this part if the corporation is the parent corporation (parent) that is neither a CCPC nor a DIC in a tax year and has, in the year, received all or substantially all of the assets on dissolution or wind-up of a subsidiary. Complete a separate worksheet for **each** subsidiary involved in the wind-up.

This adjustment to the parent's LRIP can be made at any time in the tax year that is at or after the end of the subsidiary's last tax year.

The last tax year for the subsidiary was its tax year during which its assets were distributed to the parent corporation on the wind-up.

Keep a copy of this calculation for your records in case we ask to see it later.

For a subsidiary that was a CCPC or a DIC in its last tax year

Cost amount to the subsidiary of all property immediately before the end of its last tax year . . . . ________ 1

The subsidiary's cash on hand immediately before the end of its last tax year . . . . ________ 2

Total of subsection 111(1) losses that would have been deductible in computing the subsidiary's taxable income for its last tax year if the subsidiary had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for its last tax year:

Non-capital losses . . . . ________ 3

Net capital losses . . . . ________ 4

Farm losses . . . . ________ 5

Restricted farm losses . . . . ________ 6

Limited partnership losses . . . . ________ 7

Subtotal (**add** amounts 3 to 7) ________ ► ________ 8

Total of all amounts deducted under subsection 111(1) in computing the subsidiary's taxable income for the last tax year:

Non-capital losses . . . . ________ 9

Net capital losses . . . . ________ 10

Farm losses . . . . ________ 11

Restricted farm losses . . . . ________ 12

Limited partnership losses . . . . ________ 13

Subtotal (**add** amounts 9 to 13) ________ ► ________ 14

Unused and unexpired losses at the end of the subsidiary's last tax year (amount 8 **minus** amount 14) (if negative, enter "0") . . . . ________ ► ________ 15

Subtotal (**add** amounts 1, 2, and 15) ________ 16

All of the subsidiary's debts and other obligations to pay that were outstanding immediately before the end of its last tax year . . . . ________ 17

Paid up capital of all the subsidiary's issued and outstanding shares of capital stock immediately before the end of its last tax year . . . . ________ 18

All of the subsidiary's reserves deducted in its last tax year . . . . ________ 19

The subsidiary's capital dividend account immediately before the end of its last tax year if the parent is **not** a private corporation in the tax year . . . . ________ 20

The subsidiary's general rate income pool (GRIP) at the end of its last tax year . . . . ________ 21

Eligible dividends paid in its last tax year . . . ________ 22

Excessive eligible dividend designations made in its last tax year . . . . ________ 23

Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") . . . . ________ ► ________ 24

Subtotal (amounts 21 **minus** amounts 24) ________ ► ________ 25

Subtotal (**add** amounts, 17, 18, 19, 20, 25) ________ ► ________ 26

Adjustment for a subsidiary that was a CCPC or a DIC in its last tax year (amount 16 **minus** amount 26) (if negative, enter "0") . . . ________ 27

For a subsidiary that was neither a CCPC nor a DIC in its last tax year

LRIP at the end of its last tax year . . . . ________ 28

Adjustment for a subsidiary involved in a wind-up (amount 27 **plus** amount 28**)** . . . . ________ 29

Calculate amount 29 for **each** subsidiary.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	100		
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160		B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		500,000	
Total taxable dividends paid in the tax year	200	500,000	
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Use this schedule if the corporation had a permanent establishment, under section 400 of the federal Income Tax Regulations, in Ontario at any time in the tax year and had Ontario taxable income in the year.
- Legislative references are to the federal Income Tax Act and Income Tax Regulations.
- This schedule is a worksheet only and is not required to be filed with your T2 Corporation Income Tax Return.

Part 1 – Ontario basic income tax

Ontario taxable income *	26,657,334	A
Ontario basic rate of tax for the year	11.5 %	B
Ontario basic income tax (amount A **multiplied** by amount B **)	3,065,593	C

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or amount Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

** If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, Tax Calculation Supplementary – Corporations. Otherwise, enter it on line 760 of the T2 return.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1).

Amount from line 400 of the T2 return		1		
Amount from line 405 of the T2 return		2		
Amount from line 427 of the T2 return (note)		3		
Enter the least of amounts 1, 2 or 3		▶		D

Ontario domestic factor (ODF): Taxable income for Ontario * / Taxable income for all provinces ** = 26,657,334.00 / 26,657,334 = 1.00000 E

Amount D **multiplied** by amount E		4		
Ontario taxable income (amount A from Part 1)	26,657,334	5		
Ontario small business income (lesser of amount 4 or amount 5)		▶		F

Ontario small business deduction rate for the year

Number of days in the tax year before January 1, 2018 / Number of days in the tax year 365 x 7 % = % G1

Number of days in the tax year after December 31, 2017 365 / Number of days in the tax year 365 x 8 % = 8.00000 % G2

OSBD rate for the year (rate G1 **plus** rate G2) 8.00000 % ▶ 8.00000 % G

Ontario small business deduction (amount F **multiplied** by rate G) H

Enter amount H on line 402 of Schedule 5.

* Enter amount A from Part 1.

** Includes the territories and the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Note: On November 15, 2018, the Government of Ontario announced, in Bill 57, that the reduction in the business limit relating to the amount of passive investment income for taxation years starting after December 31, 2018, will not be applied when calculating the Ontario small business deduction. As a result, the calculation on line 3 does not take the amount on line E2 of Schedule 200 (Jump Code: **J**) into account.

Part 3 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount 5) I

Enter amount I at amount K in Part 4 of this schedule or at amount B in Part 2 of Schedule 502, Ontario Tax Credit for Manufacturing and Processing, whichever applies.

Part 4 – Credit union tax reduction

Complete this part and Schedule 17, Credit Union Deductions, if the corporation was a credit union throughout the tax year.

Amount 2H from Schedule 17		J		
Ontario adjusted small business income (amount I)		K		
Subtotal (amount J **minus** amount K, if negative, enter "0")		L		
Amount L **multiplied** by amount G				M
Ontario domestic factor (amount E)			1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by amount N)				O

Enter amount O on line 410 of Schedule 5.

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Schedule 508

Ontario Research and Development Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC earned in the tax year to reduce Ontario corporate income tax payable in any of the three previous tax years;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - add an ORDTC transferred after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year. The ORDTC rate is:
  - 4.5% for tax years that end before June 1, 2016;
  - 3.5% for tax years that start after May 31, 2016; and
  - prorated for a tax year that ends on or after June 1, 2016, and includes May 31, 2016.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Complete and attach this schedule to the *T2 Corporation Income Tax Return* for the tax year.
- To claim this credit, you must also send in completed copies of the Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*, and the Schedule 31, *Investment Tax Credit - Corporations*, within 18 months of the tax year end.

Part 1 – Ontario SR&ED expenditure pool

	Line	Amount		Line	Amount	
Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	789,919	A			
Government assistance, non-government assistance, or a contract payment for eligible expenditures	105		B			
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		789,919	C			
Eligible expenditures transferred to the corporation by another corporation	110		D			
Subtotal (amount C **plus** amount D)		789,919	▶		789,919	E
Eligible expenditures the corporation transferred to another corporation				115		F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")				120	789,919	G

Part 2 – Eligible repayments

The repayment of the ORDTC is calculated using the ORDTC rate that you used to determine your tax credit at the time your eligible expenditures were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayments for tax years that end before June 1, 2016 .... **210** ______ x 4.5 % = **215** ______ H

Repayment for a tax year that ends on or after June 1, 2016 and includes May 31, 2016. Complete the proration calculation below.

Number of days in the tax year before June 1, 2016 **240** 152 / Number of days in the tax year **241** 366 x 4.5 % = 1.8689 % 1

Number of days in the tax year after May 31, 2016 **242** 214 / Number of days in the tax year **243** 366 x 3.5 % = 2.0464 % 2

Subtotal (percentage 1 **plus** percentage 2) 3.9153 % 3

Repayments for a tax year that ends on or after June 1, 2016 and includes May 31, 2016 ...... **211** ______ x percentage 3 3.9153 % = **216** ______ I

Part 2 – Eligible repayments (continued)

Repayments for tax years that start after May 31, 2016 . . . . **212** ________ x 3.5 % = **217** ________ J

Repayments made in the tax year of government or non-government assistance or contract payments that reduced eligible expenditures for first term or second term shared-use equipment acquired before 2014 . . . . **220** ________ x 1 / 4 = ________ x 4.5 % = **225** ________ K

Eligible repayments (total of amounts H to K) . . . . **229** ________ L

Part 3 – Calculation of the current part of the ORDTC

For tax years that end before June 1, 2016

Ontario SR&ED expenditure pool (amount G in Part 1) . . . . ________ x 4.5 % = **200** ________ M

ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year ***** . . . . **205** ________ N

Eligible repayments (amount L in Part 2) . . . . ________ O

Current part of the ORDTC for tax years that end before June 1, 2016 (total of amounts M to O) . . . . **230** ________ P

For a tax year that ends on or after June 1, 2016, and includes May 31, 2016

(Number of days in the tax year before June 1, 2016 / Number of days in the tax year) ________ x 4.5 % = ________ % 4

(Number of days in the tax year after May 31, 2016 / Number of days in the tax year) ________ x 3.5 % = ________ % 5

Subtotal (percentage 4 **plus** percentage 5) ________ % 6

Ontario SR&ED expenditure pool (amount G in Part 1) . . ________ x percentage 6 ________ % = **201** ________ Q

ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year ***** . . . . **206** ________ R

Eligible repayments (amount L in Part 2) . . . . ________ S

Part of the ORDTC for a tax year that ends on or after June 1, 2016, and includes May 31, 2016 (total of amounts Q to S) . . . . **231** ________ T

For tax years that start after May 31, 2016

Ontario SR&ED expenditure pool (amount G in Part 1) . . . . 789,919 x 3.5 % = **202** 27,647 U

ORDTC allocated to the corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year ***** . . . . **207** ________ V

Eligible repayments (amount L in Part 2) . . . . ________ W

The ORDTC for tax years that start after May 31, 2016 (total of amounts U to W) . . . . **232** 27,647 X

***** If there is a disposal or change of use of eligible property, see Part 7 on page 4.

Part 4 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year			406,476 Y	
ORDTC expired after 20 tax years	300		Z	
ORDTC at the beginning of the tax year (amount Y **minus** amount Z)	305		406,476 AA	
ORDTC transferred to the corporation on amalgamation or windup	310		BB	
Current part of ORDTC (amount P, T or X in Part 3 whichever applies)		27,647 CC		

Are you waiving all or part of the current part of the ORDTC? ...... **315** Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Waiver of the current part of the ORDTC	320	DD		
Subtotal (amount CC **minus** amount DD)		27,647 ▶	27,647 EE	
ORDTC available for deduction (total of amounts AA, BB and EE)			434,123 ▶	434,123 FF
ORDTC claimed ** (Enter amount GG on line 416 on page 5 of Schedule 5, *Tax Calculation Supplementary – Corporations*)			434,123 GG	
ORDTC carried back to previous tax years (from Part 5)			HH	
Subtotal (amount GG **plus** amount HH)			434,123 ▶	434,123 II
ORDTC balance at the end of the tax year (amount FF **minus** amount II)	325			JJ

** This amount cannot be more than the lesser of the following amounts:
- ORDTC available for deduction (amount FF); or
- Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 on page 5 of Schedule 5).

Part 5 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2017-12-31	Credit to be applied	901	
2nd previous tax year	2016-12-31	Credit to be applied	902	
3rd previous tax year	2015-12-31	Credit to be applied	903	

Total (total of amount 901 to 903)(enter at amount HH in Part 4)

Part 6 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from previous tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
2000-12-31	
2001-12-31	
2002-12-31	
2003-12-31	
2004-12-31	
2005-12-31	
2006-12-31	
2007-12-31	
2008-12-31	
2009-12-31	

Tax year of origin (earliest tax year first) Year / Month / Day	Credit available
2010-12-31	
2011-12-31	
2012-12-31	
2013-12-31	
2014-12-31	
2015-10-31	
2015-11-04	
2015-12-31	
2016-12-31	
2017-12-31	
Current tax year 2018-12-31	

Total (equals line 325 in Part 4)

The amount available from the 20th previous tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 7 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which incorporates the particular property previously referred to.

  Note: The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED in Ontario. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical federal investment tax credit (ITC) rate ******* of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

Complete the columns for each disposition for which a recapture applies, using the calculation formats below.

*** Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – Complete this part If you meet all of the above conditions

	KK Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	LL Amount calculated using the federal ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	MM Amount from column 700 or 710, whichever is less
1.			

Total of column MM (enter at amount WW in Part 8) NN

Part 7 – Calculation of a recapture of ORDTC (continued)

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line SS.

	OO Rate percentage that the transferee used to determine its federal ITC for qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act **720**	PP Proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition **730**	QQ Amount, if any, already provided for in Calculation 1 (this allows for the situation where only part of the cost of a property is transferred for an agreement under subsection 127(13) of the federal Act) **740**
1.			

	RR Amount determined by the formula (OO x PP) - QQ (using the columns above)	SS Federal ITC earned by the transferee for the qualified expenditure that was transferred **750**	TT Amount from column RR or SS, whichever is less
1.			

Total of column TT (enter at amount XX in Part 8) ______ UU

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205, 206, or 207 in Part 3, whichever applies. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line VV.

Corporate partner's share of the excess of ORDTC (enter at amount ZZ in Part 8) . . . . **760** ______ VV

Part 8 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount NN from Part 7) . . . . ______ WW

Recaptured federal ITC for Calculation 2 (amount UU from Part 7) . . . . ______ XX

Amount WW **plus** amount XX . . . . ______ x 23.56 % = ______ YY

Corporate partner's share of the excess of ORDTC for Calculation 3 (amount VV from Part 7) . . . . ______ ZZ

Recapture of ORDTC (amount YY **plus** amount ZZ) (enter amount AAA on line 277 on page 5 of Schedule 5) . . . . ______ AAA

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

	Current Expenditures		Capital Expenditures	
Total expenditures for SR&ED	564,698			
Add				
• payment of prior years' unpaid expenses (other than salary or wages)	+			
• prescribed proxy amount (Enter "0" if you use the traditional method)	+ 247,402			
• expenditures on shared-use equipment			+	
• other additions	+		+	
Subtotal	= 812,100		=	
Less				
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–			
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–			
• 20% of contract expenditures for SR&ED performed on your behalf	– 22,181			
• prescribed expenditures not allowed by regulations	–		–	
• other deductions	–		–	
• non-arm's length transactions				
– expenditures for non-arm's length SR&ED contracts	–			
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–		–	
Subtotal	= 789,919	I	=	II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)			= 789,919	III

Enter amount III on line 100 of Schedule 508.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	23,716,000,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		23,716,000,000
Total revenue of the corporation for the tax year **	142	5,988,000,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		5,988,000,000

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

	Line	Amount		Total	
Net income/loss per financial statements *	210			-57,270,439	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220	18,000,338			
Provision for deferred income taxes (debits)/cost of future income taxes	222	912,918,452			
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228	12,429,870			
Total patronage dividends received, not already included in net income/loss	232				
281 Add: Estimated depreciation on capitalized interest	282	3,356,377			
283	284				
Subtotal		946,705,037	▶	946,705,037	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320				
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336	53,041,781			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381 Less: Unrealized mark to market	382	412,940			
383	384				
385	386				
387	388				
389	390				
Subtotal		53,454,721	▶	53,454,721	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)	490			835,979,877	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);

– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515		835,979,877	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available				C
Net income subject to CMT calculation (if negative, enter "0")	520		835,979,877	

Amount from line 520		Number of days in the tax year before July 1, 2010 / Number of days in the tax year				
835,979,877	x	year before July 1, 2010	/ 365	x 4 % =		1
835,979,877	x	year after June 30, 2010	365 / 365	x 2.7 % =	22,571,457	2

Subtotal (amount 1 **plus** amount 2) 22,571,457 3

Gross CMT: amount on line 3 above x OAF **	540	22,571,457	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		22,571,457	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		2,631,470	
Net CMT payable (if negative, enter "0")		19,939,987	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor .... 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		44,863,160 G		
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		44,863,160 ▶	620	44,863,160
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				44,863,160 H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				I
Subtotal (amount H **minus** amount I)				44,863,160 J
Add:				
Net CMT payable (amount E from Part 3)		19,939,987		
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		19,939,987 ▶		19,939,987 K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	64,803,147 L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)			44,863,160 M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		2,631,470 1	
For a corporation that is not a life insurance corporation:			
CMT after foreign tax credit deduction (amount D from Part 3)	22,571,457 2		
For a life insurance corporation:			
Gross CMT (line 540 from Part 3)	3		
Gross SAT (line 460 from Part 6 of Schedule 512)	4		
The **greater** of amounts 3 and 4	5		
Deduct: line 2 or line 5, whichever applies:		22,571,457 6	
Subtotal (if negative, enter "0")		▶	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		2,631,470	
Deduct:			
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		3,528,714	
Subtotal (if negative, enter "0")		▶	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)			P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	1228185 Ontario Inc.	[redacted]	0	0
2	1937672 Ontario Inc.		0	0
3	1937680 Ontario Inc.		0	0
4	1937681 Ontario Inc.		0	0
5	1938454 Ontario Inc.		0	0
6	1943404 Ontario Inc.		0	0
7	2486267 Ontario Inc.		0	0
8	2486268 Ontario Inc.		0	0
9	2587264 Ontario Inc.		0	0
10	2587265 Ontario Inc.		0	0
11	Haldimand County Energy Inc.		0	0
12	Haldimand County Hydro Inc.		0	0
13	Hydro One B2M Holdings Inc.		0	0
14	Hydro One B2M LP Inc.		0	0
15	Hydro One East-West Tie Inc.		0	0
16	Hydro One Holdings Limited		0	0
17	Hydro One Inc.		0	0
18	Hydro One Indigenous Partnerships GP Inc.		0	0
19	Hydro One Lake Erie Link Management Inc.		0	0
20	Hydro One Limited		0	0
21	Hydro One Remote Communites Inc.		0	0
22	Hydro One Sault Ste. Marie Holding Corp.		0	0
23	Hydro One Sault Ste. Marie Holdings Inc.		0	0
24	Hydro One Sault Ste. Marie Inc.		0	0
25	Hydro One Telecom Inc.		0	0
26	Hydro One Telecom Link Limited		0	0
27	Municipal Billing Services Inc.		0	0
28	Norfolk Energy Inc.		0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
29	Norfolk Power Distribution Inc.	[redacted]	0	0
30	Olympus Corp.		0	0
31	Olympus Holding Corp.		0	0
32	Woodstock Hydro Services Inc.		0	0
		Total	450	550

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
Nancy Tran	(416) 345-6778

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 892,870,014

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \left(\frac{\text{amount on line 300} \;\textbf{minus}\; \$400{,}000}{\$200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300} \;\textbf{minus}\; \$400{,}000}{\$200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	[redacted]	Environmental Science
2.		Environmental Science
3.		Management
4.		Electrical Engineering
5.		Electrical Engineering
6.		Business Administration
7.		Business Administration
8.		Commerce
9.		Commerce
10.		Real Estate and Housing
11.		Real Estate and Housing
12.		Electrical Engineering
13.		Electrical Engineering
14.		Electrical and Biomedical Engineering
15.		Electrical and Biomedical Engineering
16.		Business Technology Management
17.		Accounting
18.		Accounting
19.		Management
20.		Business Administration and Management
21.		Electrical Engineering
22.		Commerce
23.		Commerce

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	[redacted]	Global Business & Digital Arts
25.		Electrical Engineering
26.		Electrical Engineering
27.		Electrical Engineering
28.		Electrical Engineering
29.		Global Management Studies
30.		Global Management Studies
31.		Electrical Engineering
32.		Electrical Engineering
33.		Business Administration
34.		Business Administration
35.		Electrical Engineering Technology
36.		Electrical Engineering
37.		Electrical Engineering
38.		Electrical Engineering
39.		Electrical Engineering
40.		Electrical Engineering
41.		Electrical Engineering Technology
42.		Global Management Studies
43.		Global Management Studies
44.		Engineering Science
45.		Engineering Science
46.		Civil Engineering Technology
47.		Electrical Engineering Technology
48.		Office Adminstration - Executive
49.		Electrical Engineering
50.		Electrical Engineering
51.		Electrical Engineering
52.		Electrical Engineering
53.		Electrical Engineering
54.		Commerce
55.		Commerce
56.		Commerce
57.		Powerline Technician
58.		Computer Engineering
59.		Computer Engineering
60.		Electrical Engineering
61.		Electrical Engineering
62.		Mechanical Engineering
63.		Electrical Engineering
64.		Electrical Engineering
65.		Electrical Engineering Technology
66.		Electrical Engineering
67.		Electrical Engineering Technology
68.		Electrical Engineering Technology
69.		Applied Science and Engineering
70.		Applied Science and Engineering
71.		Electrical Engineering Technology
72.		Computer Systems Technician
73.		Electrical Engineering
74.		Electrical Engineering
75.		Electrical Engineering
76.		Electrical Engineering
77.		Electrical Engineering
78.		Electrical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
79.	[redacted]	Electrical Engineering
80.		Electrical Engineering
81.		Electrical Engineering
82.		Accounting and Finance
83.		Accounting and Finance
84.		Accounting
85.		Accounting
86.		Business Administration
87.		Electrical Engineering
88.		Electrical Engineering
89.		Electrical Engineering
90.		Electrical Engineering
91.		Electrical and Biomedical Engineering
92.		Electrical and Biomedical Engineering
93.		Electrical Engineering
94.		Electrical and Computer Engineering
95.		Accounting
96.		Computer Science
97.		Electrical Engineering
98.		Electrical Engineering
99.		Commerce
100.		Commerce
101.		General Business
102.		Bachelor of Science
103.		Bachelor of Science
104.		Electrical Engineering
105.		Electrical Engineering
106.		Commerce
107.		Commerce
108.		Electrical Engineer Technology
109.		Electrical/Computer Engineering
110.		Electrical Engineering Technology
111.		Electrical Engineering Technology
112.		Commerce
113.		Commerce
114.		Electrical Engineering
115.		Electrical Engineering
116.		Enginerring
117.		Engineering
118.		Finance
119.		Commerce
120.		Engineering - Sustainable & Renewable Energy
121.		Engineering - Sustainable & Renewable Energy
122.		Business Administration
123.		Business Administration
124.		Electrical Engineering
125.		Electrical Engineering
126.		Management
127.		Engineering
128.		Powerline Technician
129.		Electrical Engineering
130.		Electrical Engineering
131.		Computer Engineering
132.		Computer Engineering
133.		Electrical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
134.	[redacted]	Computer Engineering
135.		Computer Engineering
136.		Electrical Engineering
137.		Electrical Engineering
138.		Electrical Engineering
139.		Management
140.		Industrial Engineering
141.		Industrial Engineering
142.		Real Estate Management
143.		Real Estate Management
144.		Geography and Environmental Management
145.		Electrical Engineering Technology
146.		Civil Engineering
147.		Management
148.		Management
149.		Management
150.		Management
151.		Electrical Engineering
152.		Electrical Engineering
153.		Electrical Engineering
154.		Commerce
155.		Commerce
156.		Electrical Engineering
157.		Commerce
158.		Commerce
159.		Electrical Engineering
160.		Electrical Engineering
161.		Electrical Engineering
162.		Electrical Engineering
163.		Management Economics and Finance
164.		Electrical Engineering
165.		Electrical Engineering Technology
166.		Electrical Engineering
167.		Electrical and Biomedical Engineering
168.		Electrical and Biomedical Engineering
169.		Real Estate
170.		Electrical Engineering
171.		Electrical Engineering
172.		Networking and IT Security
173.		Networking and IT Security
174.		Computer Engineering
175.		Computer Engineering
176.		Finance
177.		Finance
178.		BASc. Electrical Engineering
179.		BASc. Electrical Engineering
180.		BASc. Electrical Engineering
181.		Engineering
182.		Mechanical Engineering
183.		Mechanical Engineering
184.		Mechanical Engineering
185.		Electrical Engineering
186.		Electrical Engineering
187.		Office Administration Executive
188.		Electrical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
189.	[redacted]	Electrical Engineering
190.		Electrical and Computer Engineering
191.		Electrical and Computer Engineering
192.		Bachelor of Science, Environmental Studies
193.		Bachelor of Science, Environmental Studies
194.		Energy Systems Engineering Technology
195.		Energy Systems Engineering Technology
196.		Energy Systems Engineering Technology
197.		Mathematics Engineering
198.		Mathematics Engineering
199.		Mathematics Engineering
200.		Electrical Engineering
201.		Electrical Engineering
202.		Electrical Engineering
203.		Electrical Engineering
204.		Electrical Engineering
205.		Civil Engineering
206.		Electrical Engineering
207.		Electrical Engineering
208.		Electrical Engineering
209.		Electrical Engineering Technology Control
210.		Finance
211.		Accounting
212.		Bachelor of Applied Science
213.		Bachelor of Applied Science
214.		Engineering Science, Major in Electrical and Computer
215.		Computer Science
216.		Computer Science
217.		Electrical Engineering
218.		Electrical Engineering
219.		Civil Engineering Technology
220.		Electrical Engineering
221.		Electrical Engineering
222.		Real Estate Management
223.		Electrical Engineering
224.		Electrical Engineering
225.		Electrical Engineering
226.		Electrical Engineering
227.		Electrical Engineering
228.		Powerline Technician
229.		Economics
230.		Economics
231.		Economics
232.		Electrical Engineering
233.		Electrical Engineering
234.		Electrical Engineering
235.		Real Estate Management
236.		Electrical Engineering
237.		Electrical Engineering
238.		Electrical Engineering
239.		Electrical Engineering
240.		Civil Engineering
241.		Civil Engineering Technology
242.		Civil Engineering
243.		Electrical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
244.	[redacted]	Electrical Engineering
245.		Electrical Engineering
246.		Electrical Engineering
247.		Computer Engineering
248.		Electrical Engineering
249.		Electrical Engineering
250.		Electrical Engineering
251.		Computer Engineering
252.		Computer Engineering
253.		Bachelor of Science Forestry
254.		Bachelor of Science Forestry
255.		Computer Engineering
256.		Game Progamming
257.		Game Progamming
258.		Electrical Engineering
259.		Electrical Engineering
260.		Electrical Engineering
261.		Electrical Engineering
262.		Electrical Engineering
263.		Bachelor of Applied Science
264.		Bachelor of Applied Science
265.		Engineering
266.		Engineering
267.		Management and Finance
268.		Management and Finance
269.		Engineering
270.		Engineering
271.		Electrical Engineering
272.		Accounting
273.		Accounting
274.		Accounting
275.		Software Engineering
276.		Software Engineering
277.		Software Engineering
278.		Electrical Engineering
279.		Electrical Engineering
280.		Electrical Engineering
281.		Computer Systems
282.		Electrical Engineering
283.		Accounting and Financial Management
284.		Mechanical Engineering
285.		Electrical Engineering
286.		Electrical Engineering
287.		Electrical Engineering
288.		Electrical Engineering
289.		Management
290.		Management
291.		Mechanical Engineering
292.		Electrical Engineering Technology Control
293.		Electrical Engineering Technology - Control
294.		Engineering
295.		Geomatics
296.		Civil Engineering
297.		Electrical and Biomedical Engineering
298.		Electrical and Biomedical Engineering

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
299.	[redacted]	Engineering Science
300.	[redacted]	Engineering Science
301.	[redacted]	Electrical Engineering
302.	[redacted]	Electrical Engineering
303.	[redacted]	Electrical Engineering
304.	[redacted]	Electrical Engineering
305.	[redacted]	Electrical Engineering
306.	[redacted]	Electrical Engineering
307.	[redacted]	Electrical Engineering
308.	[redacted]	Electrical Engineering
309.	[redacted]	Electrical Engineering
310.	[redacted]	Electrical Engineering
311.	[redacted]	Electrical Engineering
312.	[redacted]	Electrical Engineering
313.	[redacted]	Electrical Engineering
314.	[redacted]	Management
315.	[redacted]	Management
316.	[redacted]	Civil Engineering Technology
317.	[redacted]	Applied Science and Engineering
318.	[redacted]	Applied Science and Engineering
319.	[redacted]	Electrical Engineering

		D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	[redacted]	2018-01-01	2018-04-30
2.	[redacted]	2018-05-01	2018-08-29
3.	[redacted]	2018-09-06	2018-12-31
4.	[redacted]	2018-01-01	2018-04-30
5.	[redacted]	2018-05-01	2018-08-29
6.	[redacted]	2018-05-07	2018-09-03
7.	[redacted]	2018-09-04	2018-12-31
8.	[redacted]	2018-01-01	2018-04-30
9.	[redacted]	2018-05-01	2018-08-10
10.	[redacted]	2018-01-08	2018-05-07
11.	[redacted]	2018-05-08	2018-08-31
12.	[redacted]	2018-01-01	2018-04-30
13.	[redacted]	2018-05-01	2018-08-31
14.	[redacted]	2018-01-11	2018-05-10
15.	[redacted]	2018-05-11	2018-09-05
16.	[redacted]	2018-01-01	2018-04-28
17.	[redacted]	2018-01-11	2018-05-10
18.	[redacted]	2018-05-11	2018-09-06
19.	[redacted]	2018-09-04	2018-12-31
20.	[redacted]	2018-01-02	2018-05-04
21.	[redacted]	2018-08-13	2018-12-31
22.	[redacted]	2018-01-01	2018-04-30
23.	[redacted]	2018-05-01	2018-08-31
24.	[redacted]	2018-04-30	2018-08-31
25.	[redacted]	2018-05-03	2018-08-30
26.	[redacted]	2018-08-31	2018-12-31
27.	[redacted]	2018-01-01	2018-04-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
28.	[redacted]	2018-05-01	2018-08-31
29.	[redacted]	2018-04-17	2018-08-14
30.	[redacted]	2018-08-15	2018-12-31
31.	[redacted]	2018-04-30	2018-08-27
32.	[redacted]	2018-08-28	2018-12-31
33.	[redacted]	2018-01-01	2018-04-30
34.	[redacted]	2018-05-01	2018-08-30
35.	[redacted]	2018-05-01	2018-08-31
36.	[redacted]	2018-01-02	2018-05-01
37.	[redacted]	2018-05-02	2018-08-29
38.	[redacted]	2018-08-30	2018-12-31
39.	[redacted]	2018-05-03	2018-08-30
40.	[redacted]	2018-08-31	2018-12-31
41.	[redacted]	2018-09-13	2018-12-21
42.	[redacted]	2018-04-30	2018-08-27
43.	[redacted]	2018-08-28	2018-12-22
44.	[redacted]	2018-01-01	2018-04-30
45.	[redacted]	2018-05-01	2018-08-31
46.	[redacted]	2018-05-01	2018-08-31
47.	[redacted]	2018-05-01	2018-08-31
48.	[redacted]	2018-05-10	2018-08-31
49.	[redacted]	2018-01-01	2018-04-30
50.	[redacted]	2018-05-01	2018-08-24
51.	[redacted]	2018-01-01	2018-04-30
52.	[redacted]	2018-05-01	2018-08-31
53.	[redacted]	2018-09-06	2018-12-31
54.	[redacted]	2018-08-30	2018-12-31
55.	[redacted]	2018-06-04	2018-10-01
56.	[redacted]	2018-10-02	2018-12-31
57.	[redacted]	2018-04-30	2018-08-30
58.	[redacted]	2018-01-01	2018-04-30
59.	[redacted]	2018-05-01	2018-09-01
60.	[redacted]	2018-05-03	2018-08-30
61.	[redacted]	2018-08-31	2018-12-31
62.	[redacted]	2018-09-06	2018-12-31
63.	[redacted]	2018-05-07	2018-09-03
64.	[redacted]	2018-09-04	2018-12-31
65.	[redacted]	2018-05-01	2018-08-31
66.	[redacted]	2018-05-01	2018-08-31
67.	[redacted]	2018-09-13	2018-12-29
68.	[redacted]	2018-05-01	2018-08-31
69.	[redacted]	2018-01-01	2018-04-30
70.	[redacted]	2018-05-01	2018-08-31
71.	[redacted]	2018-09-24	2018-12-21
72.	[redacted]	2018-09-27	2018-12-29
73.	[redacted]	2018-01-01	2018-04-30
74.	[redacted]	2018-05-01	2018-08-30
75.	[redacted]	2018-01-01	2018-04-30
76.	[redacted]	2018-05-01	2018-08-24
77.	[redacted]	2018-05-03	2018-08-31
78.	[redacted]	2018-01-01	2018-04-30
79.	[redacted]	2018-05-01	2018-08-31
80.	[redacted]	2018-01-01	2018-04-30
81.	[redacted]	2018-05-01	2018-08-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
82.	[redacted]	2018-01-02	2018-05-01
83.		2018-05-02	2018-09-07
84.		2018-01-01	2018-04-30
85.		2018-05-01	2018-08-31
86.		2018-01-01	2018-06-01
87.		2018-05-07	2018-09-03
88.		2018-09-04	2018-12-31
89.		2018-05-07	2018-09-03
90.		2018-09-04	2018-12-31
91.		2018-05-01	2018-08-28
92.		2018-08-29	2018-12-31
93.		2018-05-01	2018-08-31
94.		2018-01-01	2018-05-01
95.		2018-08-13	2018-12-31
96.		2018-09-04	2018-12-31
97.		2018-01-01	2018-04-30
98.		2018-05-01	2018-08-31
99.		2018-04-30	2018-08-27
100.		2018-08-28	2018-12-31
101.		2018-01-15	2018-05-04
102.		2018-01-01	2018-04-30
103.		2018-05-01	2018-08-31
104.		2018-01-01	2018-04-30
105.		2018-05-01	2018-08-31
106.		2018-05-28	2018-09-24
107.		2018-09-25	2018-12-31
108.		2018-09-06	2018-12-28
109.		2018-09-06	2018-12-31
110.		2018-01-15	2018-05-14
111.		2018-05-15	2018-09-14
112.		2018-01-01	2018-04-30
113.		2018-05-01	2018-08-31
114.		2018-05-02	2018-08-29
115.		2018-08-30	2018-12-31
116.		2018-05-01	2018-08-28
117.		2018-08-29	2018-12-31
118.		2018-01-01	2018-05-15
119.		2018-09-06	2018-12-31
120.		2018-01-01	2018-04-30
121.		2018-05-01	2018-09-05
122.		2018-01-15	2018-05-03
123.		2018-08-27	2018-12-22
124.		2018-01-01	2018-04-30
125.		2018-05-01	2018-08-31
126.		2018-01-01	2018-04-28
127.		2018-05-01	2018-07-24
128.		2018-01-02	2018-04-27
129.		2018-01-01	2018-04-30
130.		2018-05-01	2018-08-31
131.		2018-01-01	2018-04-30
132.		2018-05-01	2018-08-31
133.		2018-01-01	2018-06-28
134.		2018-01-01	2018-04-30
135.		2018-05-01	2018-08-29

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
136.	[redacted]	2018-01-02	2018-05-01
137.		2018-05-02	2018-08-29
138.		2018-08-30	2018-12-31
139.		2018-05-07	2018-08-31
140.		2018-05-14	2018-09-10
141.		2018-09-11	2018-12-31
142.		2018-01-04	2018-05-03
143.		2018-05-04	2018-08-31
144.		2018-09-06	2018-12-28
145.		2018-01-15	2018-05-04
146.		2018-09-24	2018-12-21
147.		2018-01-01	2018-04-30
148.		2018-05-01	2018-08-31
149.		2018-01-01	2018-04-30
150.		2018-05-01	2018-08-31
151.		2018-05-07	2018-09-03
152.		2018-09-04	2018-12-31
153.		2018-08-27	2018-12-31
154.		2018-01-01	2018-04-30
155.		2018-05-01	2018-08-17
156.		2018-05-01	2018-08-31
157.		2018-05-14	2018-09-10
158.		2018-09-11	2018-12-31
159.		2018-05-07	2018-09-03
160.		2018-09-04	2018-12-31
161.		2018-01-01	2018-04-30
162.		2018-05-01	2018-08-31
163.		2018-05-07	2018-08-31
164.		2018-05-14	2018-09-01
165.		2018-09-04	2018-12-31
166.		2018-08-27	2018-12-28
167.		2018-01-01	2018-04-30
168.		2018-05-01	2018-08-31
169.		2018-09-13	2018-12-31
170.		2018-05-03	2018-08-30
171.		2018-08-31	2018-12-31
172.		2018-05-07	2018-09-03
173.		2018-09-04	2018-12-31
174.		2018-05-07	2018-09-03
175.		2018-09-04	2018-12-31
176.		2018-05-01	2018-08-28
177.		2018-08-29	2018-12-31
178.		2018-01-01	2018-04-30
179.		2018-05-01	2018-08-28
180.		2018-08-29	2018-12-20
181.		2018-04-27	2018-08-31
182.		2018-01-04	2018-04-25
183.		2018-05-07	2018-09-03
184.		2018-09-04	2018-12-31
185.		2018-01-01	2018-05-02
186.		2018-09-06	2018-12-31
187.		2018-04-30	2018-08-31
188.		2018-05-07	2018-09-03
189.		2018-09-04	2018-12-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
190.	[redacted]	2018-01-01	2018-04-30
191.		2018-05-01	2018-08-31
192.		2018-05-07	2018-09-03
193.		2018-09-04	2018-12-31
194.		2018-01-08	2018-05-07
195.		2018-05-08	2018-09-04
196.		2018-09-05	2018-12-31
197.		2018-01-04	2018-05-03
198.		2018-05-04	2018-08-31
199.		2018-09-01	2018-12-21
200.		2018-05-07	2018-09-03
201.		2018-09-04	2018-12-31
202.		2018-01-01	2018-04-30
203.		2018-05-01	2018-08-28
204.		2018-08-29	2018-12-21
205.		2018-09-06	2018-12-31
206.		2018-01-04	2018-05-03
207.		2018-05-04	2018-08-31
208.		2018-09-01	2018-12-28
209.		2018-05-01	2018-09-01
210.		2018-09-06	2018-12-31
211.		2018-05-07	2018-08-31
212.		2018-01-01	2018-04-30
213.		2018-05-01	2018-08-29
214.		2018-09-06	2018-12-31
215.		2018-01-01	2018-04-30
216.		2018-05-01	2018-08-31
217.		2018-01-01	2018-04-30
218.		2018-05-01	2018-08-31
219.		2018-05-14	2018-08-31
220.		2018-05-03	2018-08-30
221.		2018-08-31	2018-12-31
222.		2018-09-13	2018-12-31
223.		2018-01-01	2018-04-30
224.		2018-05-01	2018-08-29
225.		2018-01-01	2018-04-30
226.		2018-05-01	2018-08-29
227.		2018-09-24	2018-12-21
228.		2018-01-02	2018-04-27
229.		2018-01-01	2018-04-30
230.		2018-05-01	2018-08-28
231.		2018-08-29	2018-12-29
232.		2018-01-02	2018-05-01
233.		2018-05-02	2018-08-29
234.		2018-08-30	2018-12-29
235.		2018-09-04	2018-12-21
236.		2018-09-17	2018-12-31
237.		2018-08-01	2018-12-31
238.		2018-05-10	2018-09-06
239.		2018-09-07	2018-12-31
240.		2018-08-23	2018-12-31
241.		2018-09-13	2018-12-22
242.		2018-01-01	2018-04-27
243.		2018-01-01	2018-04-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
244.	[redacted]	2018-05-01	2018-08-31
245.		2018-05-07	2018-09-03
246.		2018-09-04	2018-12-31
247.		2018-09-06	2018-12-31
248.		2018-05-03	2018-08-30
249.		2018-08-31	2018-12-31
250.		2018-08-30	2018-12-31
251.		2018-05-03	2018-08-30
252.		2018-08-31	2018-12-31
253.		2018-01-01	2018-04-30
254.		2018-05-01	2018-08-24
255.		2018-05-14	2018-09-29
256.		2018-05-07	2018-09-03
257.		2018-09-04	2018-12-31
258.		2018-01-01	2018-04-30
259.		2018-05-01	2018-08-30
260.		2018-01-01	2018-04-30
261.		2018-05-01	2018-08-30
262.		2018-08-29	2018-12-31
263.		2018-01-01	2018-04-30
264.		2018-05-01	2018-08-31
265.		2018-01-01	2018-04-30
266.		2018-05-01	2018-08-31
267.		2018-01-04	2018-05-03
268.		2018-05-04	2018-08-31
269.		2018-05-03	2018-08-30
270.		2018-08-31	2018-12-31
271.		2018-09-20	2018-12-31
272.		2018-01-15	2018-05-14
273.		2018-05-15	2018-09-11
274.		2018-09-12	2018-12-27
275.		2018-01-04	2018-05-03
276.		2018-05-04	2018-08-31
277.		2018-09-01	2018-12-28
278.		2018-01-01	2018-04-30
279.		2018-05-01	2018-08-31
280.		2018-09-24	2018-12-21
281.		2018-10-15	2018-12-31
282.		2018-05-01	2018-08-31
283.		2018-08-27	2018-12-31
284.		2018-08-02	2018-12-31
285.		2018-01-01	2018-04-30
286.		2018-05-01	2018-08-31
287.		2018-05-07	2018-09-03
288.		2018-09-04	2018-12-31
289.		2018-05-07	2018-09-03
290.		2018-09-04	2018-12-31
291.		2018-08-02	2018-12-31
292.		2018-09-13	2018-12-21
293.		2018-09-13	2018-12-21
294.		2018-10-01	2018-12-21
295.		2018-09-06	2018-12-28
296.		2018-05-01	2018-08-31
297.		2018-01-01	2018-04-30

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
298.	[redacted]	2018-05-01	2018-08-31
299.		2018-01-01	2018-04-30
300.		2018-05-01	2018-08-29
301.		2018-05-01	2018-08-28
302.		2018-08-29	2018-12-31
303.		2018-01-01	2018-04-30
304.		2018-05-01	2018-08-31
305.		2018-08-20	2018-12-31
306.		2018-01-01	2018-04-30
307.		2018-05-01	2018-08-28
308.		2018-09-24	2018-12-22
309.		2018-08-20	2018-12-31
310.		2018-01-01	2018-04-30
311.		2018-05-01	2018-08-31
312.		2018-01-01	2018-04-30
313.		2018-05-01	2018-08-31
314.		2018-01-01	2018-04-30
315.		2018-05-01	2018-09-01
316.		2018-05-01	2018-08-31
317.		2018-01-01	2018-04-30
318.		2018-05-01	2018-08-31
319.		2018-09-06	2018-12-31

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	24,316	25.000 %		17
2.		10.000 %	24,521	25.000 %		16
3.		10.000 %	16,975	25.000 %		16
4.		10.000 %	20,681	25.000 %		17
5.		10.000 %	20,855	25.000 %		16
6.		10.000 %	19,346	25.000 %		17
7.		10.000 %	19,183	25.000 %		16
8.		10.000 %	23,875	25.000 %		17
9.		10.000 %	20,264	25.000 %		14
10.		10.000 %	21,807	25.000 %		17
11.		10.000 %	21,074	25.000 %		16
12.		10.000 %	23,924	25.000 %		17
13.		10.000 %	24,125	25.000 %		17
14.		10.000 %	22,318	25.000 %		16
15.		10.000 %	21,943	25.000 %		16
16.		10.000 %	23,333	25.000 %		17
17.		10.000 %	22,492	25.000 %		16
18.		10.000 %	22,303	25.000 %		16
19.		10.000 %	15,285	25.000 %		16
20.		10.000 %	18,589	25.000 %		17
21.		10.000 %	21,340	25.000 %		20
22.		10.000 %	22,908	25.000 %		17
23.		10.000 %	23,101	25.000 %		17
24.		10.000 %	22,677	25.000 %		18
25.		10.000 %	19,429	25.000 %		16
26.		10.000 %	19,592	25.000 %		17
27.		10.000 %	23,453	25.000 %		17
28.		10.000 %	23,650	25.000 %		17
29.		10.000 %	19,572	25.000 %		16
30.		10.000 %	19,736	25.000 %		19
31.		10.000 %	19,406	25.000 %		17
32.		10.000 %	19,569	25.000 %		17
33.		10.000 %	19,833	25.000 %		17
34.		10.000 %	19,999	25.000 %		16
35.		10.000 %	17,411	25.000 %		17
36.		10.000 %	18,589	25.000 %		16
37.		10.000 %	18,589	25.000 %		16
38.		10.000 %	18,745	25.000 %		17
39.		10.000 %	19,368	25.000 %		16
40.		10.000 %	19,531	25.000 %		17
41.		10.000 %	10,357	25.000 %		14
42.		10.000 %	20,146	25.000 %		17
43.		10.000 %	19,638	25.000 %		16
44.		10.000 %	22,953	25.000 %		17
45.		10.000 %	23,146	25.000 %		17
46.		10.000 %	14,167	25.000 %		17
47.		10.000 %	17,754	25.000 %		17
48.		10.000 %	13,430	25.000 %		16
49.		10.000 %	25,438	25.000 %		17
50.		10.000 %	24,583	25.000 %		16
51.		10.000 %	23,346	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
52.		10.000 %	23,542	25.000 %		17
53.		10.000 %	14,861	25.000 %		16
54.		10.000 %	17,893	25.000 %		17
55.		10.000 %	18,826	25.000 %		17
56.		10.000 %	14,238	25.000 %		12
57.		10.000 %	19,186	25.000 %		17
58.		10.000 %	24,988	25.000 %		17
59.		10.000 %	25,198	25.000 %		17
60.		10.000 %	19,274	25.000 %		16
61.		10.000 %	19,436	25.000 %		17
62.		10.000 %	16,732	25.000 %		16
63.		10.000 %	19,415	25.000 %		17
64.		10.000 %	19,252	25.000 %		16
65.		10.000 %	14,635	25.000 %		17
66.		10.000 %	17,618	25.000 %		17
67.		10.000 %	15,104	25.000 %		15
68.		10.000 %	16,912	25.000 %		17
69.		10.000 %	26,195	25.000 %		17
70.		10.000 %	26,415	25.000 %		17
71.		10.000 %	9,257	25.000 %		13
72.		10.000 %	9,945	25.000 %		13
73.		10.000 %	24,569	25.000 %		17
74.		10.000 %	24,776	25.000 %		16
75.		10.000 %	22,357	25.000 %		17
76.		10.000 %	21,606	25.000 %		16
77.		10.000 %	19,398	25.000 %		17
78.		10.000 %	24,986	25.000 %		17
79.		10.000 %	25,196	25.000 %		17
80.		10.000 %	23,459	25.000 %		17
81.		10.000 %	23,656	25.000 %		17
82.		10.000 %	22,974	25.000 %		16
83.		10.000 %	23,167	25.000 %		18
84.		10.000 %	25,969	25.000 %		17
85.		10.000 %	26,187	25.000 %		17
86.		10.000 %	27,919	25.000 %		22
87.		10.000 %	18,140	25.000 %		17
88.		10.000 %	17,988	25.000 %		16
89.		10.000 %	19,103	25.000 %		17
90.		10.000 %	18,943	25.000 %		16
91.		10.000 %	19,159	25.000 %		16
92.		10.000 %	19,320	25.000 %		17
93.		10.000 %	11,392	25.000 %		17
94.		10.000 %	26,025	25.000 %		17
95.		10.000 %	18,682	25.000 %		20
96.		10.000 %	18,546	25.000 %		16
97.		10.000 %	23,099	25.000 %		17
98.		10.000 %	23,293	25.000 %		17
99.		10.000 %	19,406	25.000 %		17
100.		10.000 %	19,569	25.000 %		17
101.		10.000 %	13,688	25.000 %		16
102.		10.000 %	22,635	25.000 %		17
103.		10.000 %	22,826	25.000 %		17
104.		10.000 %	23,715	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
105.		10.000 %	23,915	25.000 %		17
106.		10.000 %	18,818	25.000 %		17
107.		10.000 %	15,339	25.000 %		13
108.		10.000 %	13,135	25.000 %		16
109.		10.000 %	16,975	25.000 %		16
110.		10.000 %	17,415	25.000 %		17
111.		10.000 %	17,562	25.000 %		17
112.		10.000 %	23,774	25.000 %		17
113.		10.000 %	23,974	25.000 %		17
114.		10.000 %	19,015	25.000 %		16
115.		10.000 %	19,175	25.000 %		17
116.		10.000 %	19,159	25.000 %		16
117.		10.000 %	19,320	25.000 %		17
118.		10.000 %	29,157	25.000 %		19
119.		10.000 %	16,611	25.000 %		16
120.		10.000 %	24,489	25.000 %		17
121.		10.000 %	24,695	25.000 %		17
122.		10.000 %	27,974	25.000 %		15
123.		10.000 %	27,974	25.000 %		17
124.		10.000 %	23,994	25.000 %		17
125.		10.000 %	24,195	25.000 %		17
126.		10.000 %	26,340	25.000 %		17
127.		10.000 %	16,051	25.000 %		11
128.		10.000 %	15,271	25.000 %		16
129.		10.000 %	23,695	25.000 %		17
130.		10.000 %	23,894	25.000 %		17
131.		10.000 %	23,761	25.000 %		17
132.		10.000 %	23,961	25.000 %		17
133.		10.000 %	22,817	25.000 %		25
134.		10.000 %	23,642	25.000 %		17
135.		10.000 %	23,841	25.000 %		16
136.		10.000 %	18,626	25.000 %		16
137.		10.000 %	18,626	25.000 %		16
138.		10.000 %	18,783	25.000 %		17
139.		10.000 %	21,415	25.000 %		17
140.		10.000 %	18,987	25.000 %		17
141.		10.000 %	17,710	25.000 %		15
142.		10.000 %	21,525	25.000 %		16
143.		10.000 %	21,525	25.000 %		17
144.		10.000 %	17,774	25.000 %		16
145.		10.000 %	20,695	25.000 %		16
146.		10.000 %	9,257	25.000 %		13
147.		10.000 %	21,575	25.000 %		17
148.		10.000 %	21,757	25.000 %		17
149.		10.000 %	24,651	25.000 %		17
150.		10.000 %	24,858	25.000 %		17
151.		10.000 %	19,346	25.000 %		17
152.		10.000 %	19,183	25.000 %		16
153.		10.000 %	18,915	25.000 %		18
154.		10.000 %	23,902	25.000 %		17
155.		10.000 %	21,693	25.000 %		15
156.		10.000 %	16,636	25.000 %		17
157.		10.000 %	18,612	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
158.		10.000 %	17,361	25.000 %		15
159.		10.000 %	19,157	25.000 %		17
160.		10.000 %	18,996	25.000 %		16
161.		10.000 %	23,433	25.000 %		17
162.		10.000 %	23,630	25.000 %		17
163.		10.000 %	20,081	25.000 %		17
164.		10.000 %	15,899	25.000 %		16
165.		10.000 %	13,511	25.000 %		16
166.		10.000 %	19,834	25.000 %		18
167.		10.000 %	22,214	25.000 %		17
168.		10.000 %	22,400	25.000 %		17
169.		10.000 %	15,520	25.000 %		15
170.		10.000 %	19,973	25.000 %		16
171.		10.000 %	20,141	25.000 %		17
172.		10.000 %	19,295	25.000 %		17
173.		10.000 %	19,133	25.000 %		16
174.		10.000 %	19,150	25.000 %		17
175.		10.000 %	18,989	25.000 %		16
176.		10.000 %	33,245	25.000 %		16
177.		10.000 %	22,472	25.000 %		17
178.		10.000 %	22,500	25.000 %		17
179.		10.000 %	22,500	25.000 %		16
180.		10.000 %	21,366	25.000 %		15
181.		10.000 %	14,731	25.000 %		18
182.		10.000 %	16,255	25.000 %		15
183.		10.000 %	19,157	25.000 %		17
184.		10.000 %	18,996	25.000 %		16
185.		10.000 %	25,903	25.000 %		17
186.		10.000 %	17,847	25.000 %		16
187.		10.000 %	17,548	25.000 %		18
188.		10.000 %	19,157	25.000 %		17
189.		10.000 %	18,996	25.000 %		16
190.		10.000 %	23,748	25.000 %		17
191.		10.000 %	23,947	25.000 %		17
192.		10.000 %	19,157	25.000 %		17
193.		10.000 %	18,996	25.000 %		16
194.		10.000 %	15,439	25.000 %		17
195.		10.000 %	15,439	25.000 %		16
196.		10.000 %	15,179	25.000 %		16
197.		10.000 %	19,253	25.000 %		16
198.		10.000 %	19,253	25.000 %		17
199.		10.000 %	17,959	25.000 %		16
200.		10.000 %	19,614	25.000 %		17
201.		10.000 %	19,449	25.000 %		16
202.		10.000 %	23,184	25.000 %		17
203.		10.000 %	23,184	25.000 %		16
204.		10.000 %	22,210	25.000 %		16
205.		10.000 %	16,975	25.000 %		16
206.		10.000 %	18,624	25.000 %		16
207.		10.000 %	18,624	25.000 %		17
208.		10.000 %	18,468	25.000 %		17
209.		10.000 %	17,849	25.000 %		17
210.		10.000 %	16,975	25.000 %		16

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
211.		10.000 %	22,748	25.000 %		17
212.		10.000 %	23,512	25.000 %		17
213.		10.000 %	23,710	25.000 %		16
214.		10.000 %	16,975	25.000 %		16
215.		10.000 %	20,351	25.000 %		17
216.		10.000 %	20,522	25.000 %		17
217.		10.000 %	22,140	25.000 %		17
218.		10.000 %	22,326	25.000 %		17
219.		10.000 %	14,900	25.000 %		16
220.		10.000 %	19,079	25.000 %		16
221.		10.000 %	19,239	25.000 %		17
222.		10.000 %	16,019	25.000 %		15
223.		10.000 %	22,646	25.000 %		17
224.		10.000 %	22,837	25.000 %		16
225.		10.000 %	23,885	25.000 %		17
226.		10.000 %	24,085	25.000 %		16
227.		10.000 %	9,237	25.000 %		13
228.		10.000 %	15,271	25.000 %		16
229.		10.000 %	22,604	25.000 %		17
230.		10.000 %	22,604	25.000 %		16
231.		10.000 %	22,794	25.000 %		17
232.		10.000 %	20,706	25.000 %		16
233.		10.000 %	20,706	25.000 %		16
234.		10.000 %	20,880	25.000 %		17
235.		10.000 %	17,460	25.000 %		15
236.		10.000 %	12,109	25.000 %		15
237.		10.000 %	23,280	25.000 %		21
238.		10.000 %	18,964	25.000 %		16
239.		10.000 %	18,326	25.000 %		16
240.		10.000 %	19,400	25.000 %		18
241.		10.000 %	12,903	25.000 %		14
242.		10.000 %	26,225	25.000 %		17
243.		10.000 %	23,381	25.000 %		17
244.		10.000 %	23,577	25.000 %		17
245.		10.000 %	20,550	25.000 %		17
246.		10.000 %	20,377	25.000 %		16
247.		10.000 %	16,975	25.000 %		16
248.		10.000 %	19,274	25.000 %		16
249.		10.000 %	19,436	25.000 %		17
250.		10.000 %	17,945	25.000 %		17
251.		10.000 %	18,735	25.000 %		16
252.		10.000 %	18,893	25.000 %		17
253.		10.000 %	25,415	25.000 %		17
254.		10.000 %	24,561	25.000 %		16
255.		10.000 %	27,270	25.000 %		20
256.		10.000 %	15,608	25.000 %		17
257.		10.000 %	15,477	25.000 %		16
258.		10.000 %	23,134	25.000 %		17
259.		10.000 %	23,328	25.000 %		16
260.		10.000 %	25,286	25.000 %		17
261.		10.000 %	25,499	25.000 %		16
262.		10.000 %	18,430	25.000 %		17
263.		10.000 %	22,938	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
264.		10.000 %	23,131	25.000 %		17
265.		10.000 %	22,236	25.000 %		17
266.		10.000 %	22,423	25.000 %		17
267.		10.000 %	20,573	25.000 %		16
268.		10.000 %	20,573	25.000 %		17
269.		10.000 %	18,673	25.000 %		16
270.		10.000 %	18,830	25.000 %		17
271.		10.000 %	14,550	25.000 %		14
272.		10.000 %	15,048	25.000 %		17
273.		10.000 %	15,048	25.000 %		16
274.		10.000 %	13,404	25.000 %		14
275.		10.000 %	18,807	25.000 %		16
276.		10.000 %	18,807	25.000 %		17
277.		10.000 %	18,649	25.000 %		17
278.		10.000 %	23,364	25.000 %		17
279.		10.000 %	23,561	25.000 %		17
280.		10.000 %	13,339	25.000 %		13
281.		10.000 %	8,069	25.000 %		11
282.		10.000 %	14,828	25.000 %		17
283.		10.000 %	18,915	25.000 %		18
284.		10.000 %	24,471	25.000 %		21
285.		10.000 %	22,674	25.000 %		17
286.		10.000 %	22,865	25.000 %		17
287.		10.000 %	19,224	25.000 %		17
288.		10.000 %	19,063	25.000 %		16
289.		10.000 %	19,346	25.000 %		17
290.		10.000 %	19,183	25.000 %		16
291.		10.000 %	23,037	25.000 %		21
292.		10.000 %	12,798	25.000 %		14
293.		10.000 %	10,954	25.000 %		14
294.		10.000 %	8,459	25.000 %		12
295.		10.000 %	18,031	25.000 %		16
296.		10.000 %	15,098	25.000 %		17
297.		10.000 %	22,326	25.000 %		17
298.		10.000 %	22,513	25.000 %		17
299.		10.000 %	22,363	25.000 %		17
300.		10.000 %	22,551	25.000 %		16
301.		10.000 %	19,362	25.000 %		16
302.		10.000 %	19,525	25.000 %		17
303.		10.000 %	22,394	25.000 %		17
304.		10.000 %	22,582	25.000 %		17
305.		10.000 %	15,575	25.000 %		19
306.		10.000 %	15,211	25.000 %		17
307.		10.000 %	15,211	25.000 %		16
308.		10.000 %	11,024	25.000 %		13
309.		10.000 %	18,554	25.000 %		19
310.		10.000 %	24,477	25.000 %		17
311.		10.000 %	24,683	25.000 %		17
312.		10.000 %	21,977	25.000 %		17
313.		10.000 %	22,162	25.000 %		17
314.		10.000 %	22,144	25.000 %		17
315.		10.000 %	22,330	25.000 %		17
316.		10.000 %	17,751	25.000 %		17

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
317.		10.000 %	25,194	25.000 %		17
318.		10.000 %	25,405	25.000 %		17
319.		10.000 %	16,975	25.000 %		16

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	6,079	3,000	3,000		3,000
2.	6,130	3,000	3,000		3,000
3.	4,244	3,000	3,000		3,000
4.	5,170	3,000	3,000		3,000
5.	5,214	3,000	3,000		3,000
6.	4,837	3,000	3,000		3,000
7.	4,796	3,000	3,000		3,000
8.	5,969	3,000	3,000		3,000
9.	5,066	3,000	3,000		3,000
10.	5,452	3,000	3,000		3,000
11.	5,269	3,000	3,000		3,000
12.	5,981	3,000	3,000		3,000
13.	6,031	3,000	3,000		3,000
14.	5,580	3,000	3,000		3,000
15.	5,486	3,000	3,000		3,000
16.	5,833	3,000	3,000		3,000
17.	5,623	3,000	3,000		3,000
18.	5,576	3,000	3,000		3,000
19.	3,821	3,000	3,000		3,000
20.	4,647	3,000	3,000		3,000
21.	5,335	3,000	3,000		3,000
22.	5,727	3,000	3,000		3,000
23.	5,775	3,000	3,000		3,000
24.	5,669	3,000	3,000		3,000
25.	4,857	3,000	3,000		3,000
26.	4,898	3,000	3,000		3,000
27.	5,863	3,000	3,000		3,000
28.	5,913	3,000	3,000		3,000
29.	4,893	3,000	3,000		3,000
30.	4,934	3,000	3,000		3,000
31.	4,852	3,000	3,000		3,000
32.	4,892	3,000	3,000		3,000
33.	4,958	3,000	3,000		3,000
34.	5,000	3,000	3,000		3,000
35.	4,353	3,000	3,000		3,000
36.	4,647	3,000	3,000		3,000
37.	4,647	3,000	3,000		3,000
38.	4,686	3,000	3,000		3,000
39.	4,842	3,000	3,000		3,000
40.	4,883	3,000	3,000		3,000
41.	2,589	3,000	2,589		2,589
42.	5,037	3,000	3,000		3,000
43.	4,910	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
44.	5,738	3,000	3,000		3,000
45.	5,787	3,000	3,000		3,000
46.	3,542	3,000	3,000		3,000
47.	4,439	3,000	3,000		3,000
48.	3,358	3,000	3,000		3,000
49.	6,360	3,000	3,000		3,000
50.	6,146	3,000	3,000		3,000
51.	5,837	3,000	3,000		3,000
52.	5,886	3,000	3,000		3,000
53.	3,715	3,000	3,000		3,000
54.	4,473	3,000	3,000		3,000
55.	4,707	3,000	3,000		3,000
56.	3,560	3,000	3,000		3,000
57.	4,797	3,000	3,000		3,000
58.	6,247	3,000	3,000		3,000
59.	6,300	3,000	3,000		3,000
60.	4,819	3,000	3,000		3,000
61.	4,859	3,000	3,000		3,000
62.	4,183	3,000	3,000		3,000
63.	4,854	3,000	3,000		3,000
64.	4,813	3,000	3,000		3,000
65.	3,659	3,000	3,000		3,000
66.	4,405	3,000	3,000		3,000
67.	3,776	3,000	3,000		3,000
68.	4,228	3,000	3,000		3,000
69.	6,549	3,000	3,000		3,000
70.	6,604	3,000	3,000		3,000
71.	2,314	3,000	2,314		2,314
72.	2,486	3,000	2,486		2,486
73.	6,142	3,000	3,000		3,000
74.	6,194	3,000	3,000		3,000
75.	5,589	3,000	3,000		3,000
76.	5,402	3,000	3,000		3,000
77.	4,850	3,000	3,000		3,000
78.	6,247	3,000	3,000		3,000
79.	6,299	3,000	3,000		3,000
80.	5,865	3,000	3,000		3,000
81.	5,914	3,000	3,000		3,000
82.	5,744	3,000	3,000		3,000
83.	5,792	3,000	3,000		3,000
84.	6,492	3,000	3,000		3,000
85.	6,547	3,000	3,000		3,000
86.	6,980	3,000	3,000		3,000
87.	4,535	3,000	3,000		3,000
88.	4,497	3,000	3,000		3,000
89.	4,776	3,000	3,000		3,000
90.	4,736	3,000	3,000		3,000
91.	4,790	3,000	3,000		3,000
92.	4,830	3,000	3,000		3,000
93.	2,848	3,000	2,848		2,848
94.	6,506	3,000	3,000		3,000
95.	4,671	3,000	3,000		3,000
96.	4,637	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
97.	5,775	3,000	3,000		3,000
98.	5,823	3,000	3,000		3,000
99.	4,852	3,000	3,000		3,000
100.	4,892	3,000	3,000		3,000
101.	3,422	3,000	3,000		3,000
102.	5,659	3,000	3,000		3,000
103.	5,707	3,000	3,000		3,000
104.	5,929	3,000	3,000		3,000
105.	5,979	3,000	3,000		3,000
106.	4,705	3,000	3,000		3,000
107.	3,835	3,000	3,000		3,000
108.	3,284	3,000	3,000		3,000
109.	4,244	3,000	3,000		3,000
110.	4,354	3,000	3,000		3,000
111.	4,391	3,000	3,000		3,000
112.	5,944	3,000	3,000		3,000
113.	5,994	3,000	3,000		3,000
114.	4,754	3,000	3,000		3,000
115.	4,794	3,000	3,000		3,000
116.	4,790	3,000	3,000		3,000
117.	4,830	3,000	3,000		3,000
118.	7,289	3,000	3,000		3,000
119.	4,153	3,000	3,000		3,000
120.	6,122	3,000	3,000		3,000
121.	6,174	3,000	3,000		3,000
122.	6,994	3,000	3,000		3,000
123.	6,994	3,000	3,000		3,000
124.	5,999	3,000	3,000		3,000
125.	6,049	3,000	3,000		3,000
126.	6,585	3,000	3,000		3,000
127.	4,013	3,000	3,000		3,000
128.	3,818	3,000	3,000		3,000
129.	5,924	3,000	3,000		3,000
130.	5,974	3,000	3,000		3,000
131.	5,940	3,000	3,000		3,000
132.	5,990	3,000	3,000		3,000
133.	5,704	3,000	3,000		3,000
134.	5,911	3,000	3,000		3,000
135.	5,960	3,000	3,000		3,000
136.	4,657	3,000	3,000		3,000
137.	4,657	3,000	3,000		3,000
138.	4,696	3,000	3,000		3,000
139.	5,354	3,000	3,000		3,000
140.	4,747	3,000	3,000		3,000
141.	4,428	3,000	3,000		3,000
142.	5,381	3,000	3,000		3,000
143.	5,381	3,000	3,000		3,000
144.	4,444	3,000	3,000		3,000
145.	5,174	3,000	3,000		3,000
146.	2,314	3,000	2,314		2,314
147.	5,394	3,000	3,000		3,000
148.	5,439	3,000	3,000		3,000
149.	6,163	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
150.	6,215	3,000	3,000		3,000
151.	4,837	3,000	3,000		3,000
152.	4,796	3,000	3,000		3,000
153.	4,729	3,000	3,000		3,000
154.	5,976	3,000	3,000		3,000
155.	5,423	3,000	3,000		3,000
156.	4,159	3,000	3,000		3,000
157.	4,653	3,000	3,000		3,000
158.	4,340	3,000	3,000		3,000
159.	4,789	3,000	3,000		3,000
160.	4,749	3,000	3,000		3,000
161.	5,858	3,000	3,000		3,000
162.	5,908	3,000	3,000		3,000
163.	5,020	3,000	3,000		3,000
164.	3,975	3,000	3,000		3,000
165.	3,378	3,000	3,000		3,000
166.	4,959	3,000	3,000		3,000
167.	5,554	3,000	3,000		3,000
168.	5,600	3,000	3,000		3,000
169.	3,880	3,000	3,000		3,000
170.	4,993	3,000	3,000		3,000
171.	5,035	3,000	3,000		3,000
172.	4,824	3,000	3,000		3,000
173.	4,783	3,000	3,000		3,000
174.	4,788	3,000	3,000		3,000
175.	4,747	3,000	3,000		3,000
176.	8,311	3,000	3,000		3,000
177.	5,618	3,000	3,000		3,000
178.	5,625	3,000	3,000		3,000
179.	5,625	3,000	3,000		3,000
180.	5,342	3,000	3,000		3,000
181.	3,683	3,000	3,000		3,000
182.	4,064	3,000	3,000		3,000
183.	4,789	3,000	3,000		3,000
184.	4,749	3,000	3,000		3,000
185.	6,476	3,000	3,000		3,000
186.	4,462	3,000	3,000		3,000
187.	4,387	3,000	3,000		3,000
188.	4,789	3,000	3,000		3,000
189.	4,749	3,000	3,000		3,000
190.	5,937	3,000	3,000		3,000
191.	5,987	3,000	3,000		3,000
192.	4,789	3,000	3,000		3,000
193.	4,749	3,000	3,000		3,000
194.	3,860	3,000	3,000		3,000
195.	3,860	3,000	3,000		3,000
196.	3,795	3,000	3,000		3,000
197.	4,813	3,000	3,000		3,000
198.	4,813	3,000	3,000		3,000
199.	4,490	3,000	3,000		3,000
200.	4,904	3,000	3,000		3,000
201.	4,862	3,000	3,000		3,000
202.	5,796	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
203.	5,796	3,000	3,000		3,000
204.	5,553	3,000	3,000		3,000
205.	4,244	3,000	3,000		3,000
206.	4,656	3,000	3,000		3,000
207.	4,656	3,000	3,000		3,000
208.	4,617	3,000	3,000		3,000
209.	4,462	3,000	3,000		3,000
210.	4,244	3,000	3,000		3,000
211.	5,687	3,000	3,000		3,000
212.	5,878	3,000	3,000		3,000
213.	5,928	3,000	3,000		3,000
214.	4,244	3,000	3,000		3,000
215.	5,088	3,000	3,000		3,000
216.	5,131	3,000	3,000		3,000
217.	5,535	3,000	3,000		3,000
218.	5,582	3,000	3,000		3,000
219.	3,725	3,000	3,000		3,000
220.	4,770	3,000	3,000		3,000
221.	4,810	3,000	3,000		3,000
222.	4,005	3,000	3,000		3,000
223.	5,662	3,000	3,000		3,000
224.	5,709	3,000	3,000		3,000
225.	5,971	3,000	3,000		3,000
226.	6,021	3,000	3,000		3,000
227.	2,309	3,000	2,309		2,309
228.	3,818	3,000	3,000		3,000
229.	5,651	3,000	3,000		3,000
230.	5,651	3,000	3,000		3,000
231.	5,699	3,000	3,000		3,000
232.	5,177	3,000	3,000		3,000
233.	5,177	3,000	3,000		3,000
234.	5,220	3,000	3,000		3,000
235.	4,365	3,000	3,000		3,000
236.	3,027	3,000	3,000		3,000
237.	5,820	3,000	3,000		3,000
238.	4,741	3,000	3,000		3,000
239.	4,582	3,000	3,000		3,000
240.	4,850	3,000	3,000		3,000
241.	3,226	3,000	3,000		3,000
242.	6,556	3,000	3,000		3,000
243.	5,845	3,000	3,000		3,000
244.	5,894	3,000	3,000		3,000
245.	5,138	3,000	3,000		3,000
246.	5,094	3,000	3,000		3,000
247.	4,244	3,000	3,000		3,000
248.	4,819	3,000	3,000		3,000
249.	4,859	3,000	3,000		3,000
250.	4,486	3,000	3,000		3,000
251.	4,684	3,000	3,000		3,000
252.	4,723	3,000	3,000		3,000
253.	6,354	3,000	3,000		3,000
254.	6,140	3,000	3,000		3,000
255.	6,818	3,000	3,000		3,000

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
256.	3,902	3,000	3,000		3,000
257.	3,869	3,000	3,000		3,000
258.	5,784	3,000	3,000		3,000
259.	5,832	3,000	3,000		3,000
260.	6,322	3,000	3,000		3,000
261.	6,375	3,000	3,000		3,000
262.	4,608	3,000	3,000		3,000
263.	5,735	3,000	3,000		3,000
264.	5,783	3,000	3,000		3,000
265.	5,559	3,000	3,000		3,000
266.	5,606	3,000	3,000		3,000
267.	5,143	3,000	3,000		3,000
268.	5,143	3,000	3,000		3,000
269.	4,668	3,000	3,000		3,000
270.	4,708	3,000	3,000		3,000
271.	3,638	3,000	3,000		3,000
272.	3,762	3,000	3,000		3,000
273.	3,762	3,000	3,000		3,000
274.	3,351	3,000	3,000		3,000
275.	4,702	3,000	3,000		3,000
276.	4,702	3,000	3,000		3,000
277.	4,662	3,000	3,000		3,000
278.	5,841	3,000	3,000		3,000
279.	5,890	3,000	3,000		3,000
280.	3,335	3,000	3,000		3,000
281.	2,017	3,000	2,017		2,017
282.	3,707	3,000	3,000		3,000
283.	4,729	3,000	3,000		3,000
284.	6,118	3,000	3,000		3,000
285.	5,669	3,000	3,000		3,000
286.	5,716	3,000	3,000		3,000
287.	4,806	3,000	3,000		3,000
288.	4,766	3,000	3,000		3,000
289.	4,837	3,000	3,000		3,000
290.	4,796	3,000	3,000		3,000
291.	5,759	3,000	3,000		3,000
292.	3,200	3,000	3,000		3,000
293.	2,739	3,000	2,739		2,739
294.	2,115	3,000	2,115		2,115
295.	4,508	3,000	3,000		3,000
296.	3,775	3,000	3,000		3,000
297.	5,582	3,000	3,000		3,000
298.	5,628	3,000	3,000		3,000
299.	5,591	3,000	3,000		3,000
300.	5,638	3,000	3,000		3,000
301.	4,841	3,000	3,000		3,000
302.	4,881	3,000	3,000		3,000
303.	5,599	3,000	3,000		3,000
304.	5,646	3,000	3,000		3,000
305.	3,894	3,000	3,000		3,000
306.	3,803	3,000	3,000		3,000
307.	3,803	3,000	3,000		3,000
308.	2,756	3,000	2,756		2,756

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
309.	4,639	3,000	3,000		3,000
310.	6,119	3,000	3,000		3,000
311.	6,171	3,000	3,000		3,000
312.	5,494	3,000	3,000		3,000
313.	5,541	3,000	3,000		3,000
314.	5,536	3,000	3,000		3,000
315.	5,583	3,000	3,000		3,000
316.	4,438	3,000	3,000		3,000
317.	6,299	3,000	3,000		3,000
318.	6,351	3,000	3,000		3,000
319.	4,244	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 500 951,487 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ... ______ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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Schedule 552

Ontario Apprenticeship Training Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.	87086 5821 RC0001	2018-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	**120** Telephone number
Nancy Tran	(416) 345-6778

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ____

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 892,870,014

For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \;\textbf{minus}\; 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . **312** 35.000 %

For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\textbf{minus}\; 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
1.	309a	Electrician-Construction and Maintenance	[redacted]
2.	309a	Electrician-Construction and Maintenance	[redacted]
3.	309a	Electrician-Construction and Maintenance	[redacted]
4.	309a	Electrician-Construction and Maintenance	[redacted]
5.	309a	Electrician-Construction and Maintenance	[redacted]
6.	309a	Electrician-Construction and Maintenance	[redacted]
7.	309a	Electrician-Construction and Maintenance	[redacted]
8.	309a	Electrician-Construction and Maintenance	[redacted]
9.	309a	Electrician-Construction and Maintenance	[redacted]
10.	309a	Electrician-Construction and Maintenance	[redacted]
11.	309a	Electrician-Construction and Maintenance	[redacted]
12.	309a	Electrician-Construction and Maintenance	[redacted]
13.	309a	Electrician-Construction and Maintenance	[redacted]
14.	309a	Electrician-Construction and Maintenance	[redacted]
15.	309a	Electrician-Construction and Maintenance	[redacted]
16.	309a	Electrician-Construction and Maintenance	[redacted]
17.	309a	Electrician-Construction and Maintenance	[redacted]
18.	309a	Electrician-Construction and Maintenance	[redacted]
19.	309a	Electrician-Construction and Maintenance	[redacted]
20.	309a	Electrician-Construction and Maintenance	[redacted]
21.	309a	Electrician-Construction and Maintenance	[redacted]
22.	309a	Electrician-Construction and Maintenance	[redacted]
23.	309a	Electrician-Construction and Maintenance	[redacted]
24.	309a	Electrician-Construction and Maintenance	[redacted]
25.	309a	Electrician-Construction and Maintenance	[redacted]
26.	309a	Electrician-Construction and Maintenance	[redacted]
27.	434a	Powerline Technician	[redacted]

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
28.	434a	Powerline Technician	[redacted]
29.	434a	Powerline Technician	
30.	434a	Powerline Technician	
31.	310t	Truck And Coach Technician	
32.	434a	Powerline Technician	
33.	434a	Powerline Technician	
34.	434a	Powerline Technician	
35.	434a	Powerline Technician	
36.	434a	Powerline Technician	
37.	434a	Powerline Technician	
38.	434a	Powerline Technician	
39.	434a	Powerline Technician	
40.	434a	Powerline Technician	
41.	434a	Powerline Technician	
42.	310t	Truck And Coach Technician	
43.	434a	Powerline Technician	
44.	434a	Powerline Technician	
45.	434a	Powerline Technician	
46.	434a	Powerline Technician	
47.	434a	Powerline Technician	
48.	434a	Powerline Technician	
49.	434a	Powerline Technician	
50.	434a	Powerline Technician	
51.	434a	Powerline Technician	
52.	434a	Powerline Technician	
53.	434a	Powerline Technician	
54.	434a	Powerline Technician	
55.	434a	Powerline Technician	
56.	434a	Powerline Technician	
57.	434a	Powerline Technician	
58.	434a	Powerline Technician	
59.	434a	Powerline Technician	
60.	434a	Powerline Technician	
61.	434a	Powerline Technician	
62.	434a	Powerline Technician	
63.	434a	Powerline Technician	
64.	434a	Powerline Technician	
65.	434a	Powerline Technician	
66.	434a	Powerline Technician	
67.	434a	Powerline Technician	
68.	434a	Powerline Technician	
69.	434a	Powerline Technician	
70.	434a	Powerline Technician	
71.	434a	Powerline Technician	
72.	434a	Powerline Technician	
73.	434a	Powerline Technician	
74.	434a	Powerline Technician	
75.	434a	Powerline Technician	
76.	434a	Powerline Technician	
77.	434a	Powerline Technician	
78.	434a	Powerline Technician	
79.	434a	Powerline Technician	
80.	310t	Truck And Coach Technician	
81.	434a	Powerline Technician	
82.	309a	Electrician-Construction and Maintenance	

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
83.	434a	Powerline Technician	[redacted]
84.	434a	Powerline Technician	[redacted]
85.	310t	Truck And Coach Technician	[redacted]
86.	434a	Powerline Technician	[redacted]
87.	309a	Electrician-Construction and Maintenance	[redacted]
88.	309a	Electrician-Construction and Maintenance	[redacted]
89.	309a	Electrician-Construction and Maintenance	[redacted]
90.	309a	Electrician-Construction and Maintenance	[redacted]
91.	434a	Powerline Technician	[redacted]
92.	309a	Electrician-Construction and Maintenance	[redacted]
93.	309a	Electrician-Construction and Maintenance	[redacted]
94.	434a	Powerline Technician	[redacted]
95.	434a	Powerline Technician	[redacted]
96.	434a	Powerline Technician	[redacted]
97.	434a	Powerline Technician	[redacted]
98.	434a	Powerline Technician	[redacted]
99.	434a	Powerline Technician	[redacted]
100.	434a	Powerline Technician	[redacted]
101.	434a	Powerline Technician	[redacted]
102.	434a	Powerline Technician	[redacted]
103.	434a	Powerline Technician	[redacted]
104.	434a	Powerline Technician	[redacted]
105.	309a	Electrician-Construction and Maintenance	[redacted]
106.	309a	Electrician-Construction and Maintenance	[redacted]
107.	309a	Electrician-Construction and Maintenance	[redacted]
108.	434a	Powerline Technician	[redacted]
109.	434a	Powerline Technician	[redacted]
110.	434a	Powerline Technician	[redacted]
111.	434a	Powerline Technician	[redacted]
112.	434a	Powerline Technician	[redacted]
113.	309a	Electrician-Construction and Maintenance	[redacted]
114.	434a	Powerline Technician	[redacted]
115.	434a	Powerline Technician	[redacted]
116.	434a	Powerline Technician	[redacted]
117.	309a	Electrician-Construction and Maintenance	[redacted]
118.	309a	Electrician-Construction and Maintenance	[redacted]
119.	309a	Electrician-Construction and Maintenance	[redacted]
120.	309a	Electrician-Construction and Maintenance	[redacted]
121.	309a	Electrician-Construction and Maintenance	[redacted]
122.	309a	Electrician-Construction and Maintenance	[redacted]
123.	309a	Electrician-Construction and Maintenance	[redacted]
124.	309a	Electrician-Construction and Maintenance	[redacted]
125.	434a	Powerline Technician	[redacted]
126.	434a	Powerline Technician	[redacted]
127.	434a	Powerline Technician	[redacted]
128.	434a	Powerline Technician	[redacted]
129.	434a	Powerline Technician	[redacted]
130.	434a	Powerline Technician	[redacted]
131.	309a	Electrician-Construction and Maintenance	[redacted]
132.	309a	Electrician-Construction and Maintenance	[redacted]
133.	309a	Electrician-Construction and Maintenance	[redacted]
134.	434a	Powerline Technician	[redacted]
135.	309a	Electrician-Construction and Maintenance	[redacted]
136.	310t	Truck And Coach Technician	[redacted]
137.	309a	Electrician-Construction and Maintenance	[redacted]

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
138.	309a	Electrician-Construction and Maintenance	[redacted]
139.	434a	Powerline Technician	
140.	310t	Truck And Coach Technician	
141.	310t	Truck And Coach Technician	
142.	309a	Electrician-Construction and Maintenance	
143.	434a	Powerline Technician	
144.	309a	Electrician-Construction and Maintenance	
145.	309a	Electrician-Construction and Maintenance	
146.	434a	Powerline Technician	
147.	434a	Powerline Technician	
148.	434a	Powerline Technician	
149.	433a	Industrial Mechanic (Millwright)	
150.	434a	Powerline Technician	
151.	434a	Powerline Technician	
152.	434a	Powerline Technician	
153.	434a	Powerline Technician	
154.	434a	Powerline Technician	
155.	434a	Powerline Technician	
156.	434a	Powerline Technician	
157.	434a	Powerline Technician	
158.	434a	Powerline Technician	
159.	434a	Powerline Technician	
160.	434a	Powerline Technician	
161.	434a	Powerline Technician	
162.	434a	Powerline Technician	
163.	434a	Powerline Technician	
164.	434a	Powerline Technician	
165.	434a	Powerline Technician	
166.	434a	Powerline Technician	
167.	434a	Powerline Technician	
168.	434a	Powerline Technician	
169.	434a	Powerline Technician	
170.	434a	Powerline Technician	
171.	434a	Powerline Technician	
172.	434a	Powerline Technician	
173.	434a	Powerline Technician	
174.	434a	Powerline Technician	
175.	434a	Powerline Technician	
176.	434a	Powerline Technician	
177.	309a	Electrician-Construction and Maintenance	
178.	309a	Electrician-Construction and Maintenance	
179.	309a	Electrician-Construction and Maintenance	
180.	309a	Electrician-Construction and Maintenance	
181.	433a	Industrial Mechanic (Millwright)	
182.	309a	Electrician-Construction and Maintenance	
183.	309a	Electrician-Construction and Maintenance	
184.	434a	Powerline Technician	
185.	434a	Powerline Technician	
186.	434a	Powerline Technician	
187.	434a	Powerline Technician	
188.	434a	Powerline Technician	
189.	434a	Powerline Technician	
190.	309a	Electrician-Construction and Maintenance	
191.	434a	Powerline Technician	
192.	310t	Truck And Coach Technician	

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
193.	434a	Powerline Technician	[redacted]
194.	434a	Powerline Technician	[redacted]
195.	434a	Powerline Technician	[redacted]
196.	434a	Powerline Technician	[redacted]
197.	434a	Powerline Technician	[redacted]
198.	434a	Powerline Technician	[redacted]
199.	434a	Powerline Technician	[redacted]
200.	434a	Powerline Technician	[redacted]
201.	434a	Powerline Technician	[redacted]
202.	434a	Powerline Technician	[redacted]
203.	309a	Electrician-Construction and Maintenance	[redacted]
204.	309a	Electrician-Construction and Maintenance	[redacted]
205.	309a	Electrician-Construction and Maintenance	[redacted]
206.	434a	Powerline Technician	[redacted]
207.	434a	Powerline Technician	[redacted]
208.	434a	Powerline Technician	[redacted]
209.	434a	Powerline Technician	[redacted]
210.	434a	Powerline Technician	[redacted]
211.	309a	Electrician-Construction and Maintenance	[redacted]
212.	434a	Powerline Technician	[redacted]
213.	434a	Powerline Technician	[redacted]
214.	434a	Powerline Technician	[redacted]
215.	434a	Powerline Technician	[redacted]
216.	434a	Powerline Technician	[redacted]
217.	434a	Powerline Technician	[redacted]
218.	434a	Powerline Technician	[redacted]
219.	434a	Powerline Technician	[redacted]
220.	309a	Electrician-Construction and Maintenance	[redacted]
221.	309a	Electrician-Construction and Maintenance	[redacted]
222.	309a	Electrician-Construction and Maintenance	[redacted]
223.	309a	Electrician-Construction and Maintenance	[redacted]
224.	309a	Electrician-Construction and Maintenance	[redacted]
225.	309a	Electrician-Construction and Maintenance	[redacted]
226.	309a	Electrician-Construction and Maintenance	[redacted]
227.	434a	Powerline Technician	[redacted]
228.	310t	Truck And Coach Technician	[redacted]
229.	434a	Powerline Technician	[redacted]
230.	434a	Powerline Technician	[redacted]
231.	434a	Powerline Technician	[redacted]
232.	309a	Electrician-Construction and Maintenance	[redacted]
233.	434a	Powerline Technician	[redacted]
234.	434a	Powerline Technician	[redacted]
235.	434a	Powerline Technician	[redacted]
236.	434a	Powerline Technician	[redacted]
237.	434a	Powerline Technician	[redacted]
238.	434a	Powerline Technician	[redacted]
239.	434a	Powerline Technician	[redacted]
240.	309a	Electrician-Construction and Maintenance	[redacted]
241.	434a	Powerline Technician	[redacted]
242.	434a	Powerline Technician	[redacted]
243.	434a	Powerline Technician	[redacted]
244.	434a	Powerline Technician	[redacted]
245.	434a	Powerline Technician	[redacted]
246.	434a	Powerline Technician	[redacted]
247.	434a	Powerline Technician	[redacted]

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
248.	434a	Powerline Technician	[redacted]
249.	434a	Powerline Technician	
250.	434a	Powerline Technician	
251.	434a	Powerline Technician	
252.	434a	Powerline Technician	
253.	434a	Powerline Technician	
254.	434a	Powerline Technician	
255.	309a	Electrician-Construction and Maintenance	
256.	434a	Powerline Technician	
257.	403a	General Carpenter	
258.	434a	Powerline Technician	
259.	434a	Powerline Technician	
260.	434a	Powerline Technician	
261.	434a	Powerline Technician	
262.	434a	Powerline Technician	
263.	434a	Powerline Technician	
264.	434a	Powerline Technician	
265.	434a	Powerline Technician	
266.	434a	Powerline Technician	
267.	434a	Powerline Technician	
268.	434a	Powerline Technician	
269.	434a	Powerline Technician	
270.	434a	Powerline Technician	
271.	434a	Powerline Technician	
272.	434a	Powerline Technician	
273.	434a	Powerline Technician	
274.	434a	Powerline Technician	
275.	434a	Powerline Technician	
276.	434a	Powerline Technician	
277.	434a	Powerline Technician	
278.	434a	Powerline Technician	
279.	434a	Powerline Technician	
280.	434a	Powerline Technician	
281.	434a	Powerline Technician	
282.	434a	Powerline Technician	
283.	434a	Powerline Technician	
284.	434a	Powerline Technician	
285.	434a	Powerline Technician	
286.	434a	Powerline Technician	
287.	434a	Powerline Technician	
288.	434a	Powerline Technician	
289.	434a	Powerline Technician	
290.	309a	Electrician-Construction and Maintenance	
291.	309a	Electrician-Construction and Maintenance	
292.	309a	Electrician-Construction and Maintenance	
293.	309a	Electrician-Construction and Maintenance	
294.	434a	Powerline Technician	
295.	434a	Powerline Technician	
296.	434a	Powerline Technician	
297.	434a	Powerline Technician	
298.	434a	Powerline Technician	
299.	434a	Powerline Technician	
300.	434a	Powerline Technician	
301.	434a	Powerline Technician	
302.	434a	Powerline Technician	

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
303.	434a	Powerline Technician	[redacted]
304.	434a	Powerline Technician	
305.	434a	Powerline Technician	
306.	309a	Electrician-Construction and Maintenance	
307.	434a	Powerline Technician	
308.	434a	Powerline Technician	
309.	434a	Powerline Technician	
310.	434a	Powerline Technician	
311.	434a	Powerline Technician	
312.	434a	Powerline Technician	
313.	434a	Powerline Technician	
314.	434a	Powerline Technician	
315.	434a	Powerline Technician	
316.	434a	Powerline Technician	
317.	434a	Powerline Technician	
318.	434a	Powerline Technician	
319.	434a	Powerline Technician	
320.	434a	Powerline Technician	
321.	434a	Powerline Technician	
322.	434a	Powerline Technician	
323.	434a	Powerline Technician	
324.	434a	Powerline Technician	
325.	309a	Electrician-Construction and Maintenance	
326.	309a	Electrician-Construction and Maintenance	
327.	434a	Powerline Technician	
328.	434a	Powerline Technician	
329.	434a	Powerline Technician	
330.	434a	Powerline Technician	
331.	309a	Electrician-Construction and Maintenance	
332.	434a	Powerline Technician	
333.	434a	Powerline Technician	
334.	434a	Powerline Technician	
335.	434a	Powerline Technician	
336.	434a	Powerline Technician	
337.	434a	Powerline Technician	
338.	434a	Powerline Technician	
339.	434a	Powerline Technician	
340.	434a	Powerline Technician	
341.	434a	Powerline Technician	
342.	434a	Powerline Technician	
343.	434a	Powerline Technician	
344.	434a	Powerline Technician	
345.	434a	Powerline Technician	
346.	309a	Electrician-Construction and Maintenance	
347.	434a	Powerline Technician	
348.	434a	Powerline Technician	
349.	434a	Powerline Technician	
350.	434a	Powerline Technician	
351.	434a	Powerline Technician	
352.	434a	Powerline Technician	
353.	434a	Powerline Technician	
354.	434a	Powerline Technician	
355.	434a	Powerline Technician	
356.	434a	Powerline Technician	
357.	434a	Powerline Technician	

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
358.	434a	Powerline Technician	[redacted]
359.	434a	Powerline Technician	[redacted]
360.	309a	Electrician-Construction and Maintenance	[redacted]
361.	434a	Powerline Technician	[redacted]
362.	309a	Electrician-Construction and Maintenance	[redacted]
363.	309a	Electrician-Construction and Maintenance	[redacted]
364.	434a	Powerline Technician	[redacted]
365.	309a	Electrician-Construction and Maintenance	[redacted]
366.	309a	Electrician-Construction and Maintenance	[redacted]
367.	434a	Powerline Technician	[redacted]
368.	309a	Electrician-Construction and Maintenance	[redacted]
369.	309a	Electrician-Construction and Maintenance	[redacted]
370.	434a	Powerline Technician	[redacted]
371.	309a	Electrician-Construction and Maintenance	[redacted]
372.	309a	Electrician-Construction and Maintenance	[redacted]
373.	309a	Electrician-Construction and Maintenance	[redacted]
374.	434a	Powerline Technician	[redacted]
375.	434a	Powerline Technician	[redacted]
376.	434a	Powerline Technician	[redacted]
377.	309a	Electrician-Construction and Maintenance	[redacted]
378.	434a	Powerline Technician	[redacted]
379.	434a	Powerline Technician	[redacted]
380.	434a	Powerline Technician	[redacted]
381.	434a	Powerline Technician	[redacted]
382.	309a	Electrician-Construction and Maintenance	[redacted]
383.	309a	Electrician-Construction and Maintenance	[redacted]
384.	434a	Powerline Technician	[redacted]
385.	434a	Powerline Technician	[redacted]
386.	434a	Powerline Technician	[redacted]
387.	434a	Powerline Technician	[redacted]
388.	309a	Electrician-Construction and Maintenance	[redacted]
389.	309a	Electrician-Construction and Maintenance	[redacted]
390.	309a	Electrician-Construction and Maintenance	[redacted]
391.	434a	Powerline Technician	[redacted]
392.	434a	Powerline Technician	[redacted]
393.	434a	Powerline Technician	[redacted]
394.	434a	Powerline Technician	[redacted]
395.	434a	Powerline Technician	[redacted]
396.	434a	Powerline Technician	[redacted]
397.	309a	Electrician-Construction and Maintenance	[redacted]
398.	434a	Powerline Technician	[redacted]
399.	434a	Powerline Technician	[redacted]
400.	434a	Powerline Technician	[redacted]
401.	309a	Electrician-Construction and Maintenance	[redacted]
402.	309a	Electrician-Construction and Maintenance	[redacted]
403.	434a	Powerline Technician	[redacted]
404.	434a	Powerline Technician	[redacted]
405.	434a	Powerline Technician	[redacted]
406.	434a	Powerline Technician	[redacted]
407.	434a	Powerline Technician	[redacted]
408.	434a	Powerline Technician	[redacted]
409.	434a	Powerline Technician	[redacted]
410.	434a	Powerline Technician	[redacted]
411.	434a	Powerline Technician	[redacted]
412.	434a	Powerline Technician	[redacted]

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
413.	434a	Powerline Technician	[redacted]
414.	434a	Powerline Technician	
415.	434a	Powerline Technician	
416.	434a	Powerline Technician	
417.	434a	Powerline Technician	
418.	434a	Powerline Technician	
419.	434a	Powerline Technician	
420.	434a	Powerline Technician	
421.	434a	Powerline Technician	
422.	434a	Powerline Technician	
423.	434a	Powerline Technician	
424.	434a	Powerline Technician	
425.	434a	Powerline Technician	
426.	434a	Powerline Technician	
427.	434a	Powerline Technician	
428.	310t	Truck And Coach Technician	
429.	310t	Truck And Coach Technician	
430.	310t	Truck And Coach Technician	
431.	310t	Truck And Coach Technician	
432.	310t	Truck And Coach Technician	
433.	310t	Truck And Coach Technician	
434.	434a	Powerline Technician	
435.	434a	Powerline Technician	
436.	434a	Powerline Technician	
437.	434a	Powerline Technician	
438.	434a	Powerline Technician	
439.	434a	Powerline Technician	
440.	434a	Powerline Technician	
441.	434a	Powerline Technician	
442.	434a	Powerline Technician	
443.	434a	Powerline Technician	
444.	434a	Powerline Technician	
445.	434a	Powerline Technician	
446.	434a	Powerline Technician	
447.	434a	Powerline Technician	
448.	434a	Powerline Technician	
449.	403a	General Carpenter	
450.	434a	Powerline Technician	
451.	434a	Powerline Technician	
452.	434a	Powerline Technician	
453.	434a	Powerline Technician	
454.	434a	Powerline Technician	
455.	434a	Powerline Technician	
456.	434a	Powerline Technician	
457.	434a	Powerline Technician	
458.	434a	Powerline Technician	
459.	434a	Powerline Technician	
460.	434a	Powerline Technician	
461.	434a	Powerline Technician	
462.	434a	Powerline Technician	
463.	309a	Electrician-Construction and Maintenance	
464.	309a	Electrician-Construction and Maintenance	
465.	309a	Electrician-Construction and Maintenance	
466.	309a	Electrician-Construction and Maintenance	
467.	309a	Electrician-Construction and Maintenance	

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
468.	309a	Electrician-Construction and Maintenance	[redacted]
469.	309a	Electrician-Construction and Maintenance	[redacted]
470.	309a	Electrician-Construction and Maintenance	[redacted]
471.	434a	Powerline Technician	[redacted]
472.	434a	Powerline Technician	[redacted]
473.	434a	Powerline Technician	[redacted]
474.	434a	Powerline Technician	[redacted]
475.	434a	Powerline Technician	[redacted]
476.	434a	Powerline Technician	[redacted]
477.	434a	Powerline Technician	[redacted]
478.	434a	Powerline Technician	[redacted]
479.	434a	Powerline Technician	[redacted]
480.	434a	Powerline Technician	[redacted]
481.	434a	Powerline Technician	[redacted]
482.	434a	Powerline Technician	[redacted]
483.	434a	Powerline Technician	[redacted]
484.	434a	Powerline Technician	[redacted]
485.	434a	Powerline Technician	[redacted]
486.	434a	Powerline Technician	[redacted]
487.	434a	Powerline Technician	[redacted]
488.	434a	Powerline Technician	[redacted]
489.	434a	Powerline Technician	[redacted]
490.	434a	Powerline Technician	[redacted]
491.	434a	Powerline Technician	[redacted]
492.	434a	Powerline Technician	[redacted]
493.	434a	Powerline Technician	[redacted]
494.	434a	Powerline Technician	[redacted]
495.	434a	Powerline Technician	[redacted]
496.	434a	Powerline Technician	[redacted]
497.	434a	Powerline Technician	[redacted]
498.	434a	Powerline Technician	[redacted]
499.	434a	Powerline Technician	[redacted]
500.	434a	Powerline Technician	[redacted]
501.	434a	Powerline Technician	[redacted]
502.	434a	Powerline Technician	[redacted]
503.	434a	Powerline Technician	[redacted]
504.	434a	Powerline Technician	[redacted]
505.	434a	Powerline Technician	[redacted]
506.	434a	Powerline Technician	[redacted]
507.	434a	Powerline Technician	[redacted]
508.	434a	Powerline Technician	[redacted]
509.	434a	Powerline Technician	[redacted]
510.	434a	Powerline Technician	[redacted]
511.	434a	Powerline Technician	[redacted]
512.	434a	Powerline Technician	[redacted]
513.	434a	Powerline Technician	[redacted]
514.	434a	Powerline Technician	[redacted]
515.	434a	Powerline Technician	[redacted]
516.	434a	Powerline Technician	[redacted]
517.	434a	Powerline Technician	[redacted]
518.	434a	Powerline Technician	[redacted]
519.	434a	Powerline Technician	[redacted]
520.	434a	Powerline Technician	[redacted]
521.	434a	Powerline Technician	[redacted]
522.	434a	Powerline Technician	[redacted]

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
523.	434a	Powerline Technician	[redacted]
524.	434a	Powerline Technician	
525.	434a	Powerline Technician	
526.	434a	Powerline Technician	
527.	434a	Powerline Technician	
528.	434a	Powerline Technician	
529.	434a	Powerline Technician	
530.	434a	Powerline Technician	
531.	434a	Powerline Technician	
532.	309a	Electrician-Construction and Maintenance	
533.	309a	Electrician-Construction and Maintenance	
534.	309a	Electrician-Construction and Maintenance	
535.	309a	Electrician-Construction and Maintenance	
536.	309a	Electrician-Construction and Maintenance	
537.	309a	Electrician-Construction and Maintenance	
538.	309a	Electrician-Construction and Maintenance	
539.	309a	Electrician-Construction and Maintenance	
540.	309a	Electrician-Construction and Maintenance	
541.	309a	Electrician-Construction and Maintenance	
542.	309a	Electrician-Construction and Maintenance	
543.	309a	Electrician-Construction and Maintenance	
544.	434a	Powerline Technician	
545.	403a	General Carpenter	
546.	403a	General Carpenter	
547.	309a	Electrician-Construction and Maintenance	
548.	309a	Electrician-Construction and Maintenance	
549.	309a	Electrician-Construction and Maintenance	
550.	309a	Electrician-Construction and Maintenance	
551.	309a	Electrician-Construction and Maintenance	
552.	309a	Electrician-Construction and Maintenance	
553.	309a	Electrician-Construction and Maintenance	
554.	309a	Electrician-Construction and Maintenance	
555.	309a	Electrician-Construction and Maintenance	
556.	309a	Electrician-Construction and Maintenance	
557.	309a	Electrician-Construction and Maintenance	
558.	309a	Electrician-Construction and Maintenance	
559.	309a	Electrician-Construction and Maintenance	
560.	309a	Electrician-Construction and Maintenance	
561.	309a	Electrician-Construction and Maintenance	
562.	309a	Electrician-Construction and Maintenance	
563.	309a	Electrician-Construction and Maintenance	
564.	309a	Electrician-Construction and Maintenance	
565.	309a	Electrician-Construction and Maintenance	
566.	309a	Electrician-Construction and Maintenance	

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
1.	[redacted]	2016-02-05	2018-01-01	2018-01-31
2.		2014-06-25	2018-01-01	2018-03-25
3.		2014-12-15	2018-01-01	2018-03-18
4.		2016-07-26	2018-09-13	2018-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
5.	[redacted]	2016-06-07	2018-09-13	2018-12-31
6.		2014-12-15	2018-01-01	2018-05-04
7.		2014-03-18	2018-01-01	2018-03-17
8.		2014-04-04	2018-01-01	2018-04-03
9.		2014-12-15	2018-01-01	2018-06-20
10.		2014-02-05	2018-01-01	2018-02-04
11.		2014-03-11	2018-01-01	2018-03-10
12.		2014-03-18	2018-01-01	2018-03-17
13.		2014-12-15	2018-01-01	2018-06-20
14.		2014-03-11	2018-01-01	2018-03-10
15.		2014-06-11	2018-01-01	2018-06-03
16.		2014-12-15	2018-01-01	2018-08-06
17.		2014-06-08	2018-01-01	2018-06-07
18.		2016-10-11	2018-02-26	2018-12-31
19.		2017-05-11	2018-02-26	2018-12-31
20.		2017-08-17	2018-02-08	2018-12-31
21.		2014-04-09	2018-01-01	2018-04-08
22.		2016-05-10	2018-01-01	2018-12-04
23.		2014-12-15	2018-01-01	2018-12-14
24.		2014-03-11	2018-01-01	2018-03-10
25.		2016-01-29	2018-01-01	2018-11-11
26.		2014-12-15	2018-01-01	2018-12-14
27.		2014-04-28	2018-01-01	2018-01-08
28.		2014-01-27	2018-01-01	2018-01-09
29.		2014-02-24	2018-01-01	2018-01-09
30.		2014-02-24	2018-01-01	2018-01-10
31.		2014-01-13	2018-01-01	2018-01-12
32.		2014-03-17	2018-01-01	2018-01-15
33.		2014-01-27	2018-01-01	2018-01-17
34.		2014-03-17	2018-01-01	2018-01-21
35.		2014-05-26	2018-01-01	2018-01-24
36.		2014-01-27	2018-01-01	2018-01-26
37.		2014-01-27	2018-01-01	2018-01-26
38.		2014-01-27	2018-01-01	2018-01-26
39.		2014-01-27	2018-01-01	2018-01-26
40.		2014-01-27	2018-01-01	2018-01-26
41.		2014-01-27	2018-01-01	2018-01-26
42.		2015-03-19	2018-01-01	2018-01-28
43.		2014-05-02	2018-01-01	2018-02-04
44.		2014-04-28	2018-01-01	2018-02-04
45.		2014-04-28	2018-01-01	2018-02-05
46.		2014-02-24	2018-01-01	2018-02-06
47.		2015-03-23	2018-01-01	2018-02-06
48.		2014-03-17	2018-01-01	2018-02-12
49.		2014-02-24	2018-01-01	2018-02-13
50.		2014-04-04	2018-01-01	2018-02-13
51.		2014-03-17	2018-01-01	2018-02-13
52.		2014-02-24	2018-01-01	2018-02-23
53.		2014-02-24	2018-01-01	2018-02-23
54.		2014-02-24	2018-01-01	2018-02-23
55.		2014-02-24	2018-01-01	2018-02-23
56.		2014-02-24	2018-01-01	2018-02-23
57.		2014-02-24	2018-01-01	2018-02-23

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
58.	[redacted]	2014-02-24	2018-01-01	2018-02-23
59.	[redacted]	2014-02-24	2018-01-01	2018-02-23
60.	[redacted]	2014-02-24	2018-01-01	2018-02-23
61.	[redacted]	2014-02-24	2018-01-01	2018-02-23
62.	[redacted]	2014-02-24	2018-01-01	2018-02-23
63.	[redacted]	2014-05-26	2018-01-01	2018-02-26
64.	[redacted]	2014-04-28	2018-01-01	2018-02-28
65.	[redacted]	2014-04-28	2018-01-01	2018-03-05
66.	[redacted]	2015-03-23	2018-01-01	2018-03-06
67.	[redacted]	2014-05-26	2018-01-01	2018-03-12
68.	[redacted]	2014-05-26	2018-01-01	2018-03-14
69.	[redacted]	2014-03-17	2018-01-01	2018-03-16
70.	[redacted]	2014-03-17	2018-01-01	2018-03-16
71.	[redacted]	2014-03-17	2018-01-01	2018-03-16
72.	[redacted]	2014-03-17	2018-01-01	2018-03-16
73.	[redacted]	2014-03-17	2018-01-01	2018-03-16
74.	[redacted]	2014-03-17	2018-01-01	2018-03-16
75.	[redacted]	2014-05-26	2018-01-01	2018-03-18
76.	[redacted]	2014-05-26	2018-01-01	2018-03-21
77.	[redacted]	2014-04-28	2018-01-01	2018-03-21
78.	[redacted]	2015-08-11	2018-01-01	2018-03-25
79.	[redacted]	2014-05-26	2018-01-01	2018-03-27
80.	[redacted]	2016-02-02	2018-10-01	2018-12-31
81.	[redacted]	2014-04-04	2018-01-01	2018-04-03
82.	[redacted]	2014-04-09	2018-01-01	2018-04-03
83.	[redacted]	2015-02-20	2018-01-01	2018-04-04
84.	[redacted]	2015-10-13	2018-01-01	2018-04-04
85.	[redacted]	2016-02-02	2018-01-01	2018-04-08
86.	[redacted]	2014-04-09	2018-01-01	2018-04-08
87.	[redacted]	2014-05-26	2018-01-01	2018-04-08
88.	[redacted]	2014-05-26	2018-01-01	2018-04-08
89.	[redacted]	2014-05-26	2018-01-01	2018-04-10
90.	[redacted]	2016-01-29	2018-01-01	2018-04-10
91.	[redacted]	2015-03-03	2018-01-01	2018-04-15
92.	[redacted]	2017-10-04	2018-01-01	2018-04-16
93.	[redacted]	2017-01-18	2018-09-13	2018-12-31
94.	[redacted]	2014-04-28	2018-01-01	2018-04-22
95.	[redacted]	2014-05-26	2018-01-01	2018-04-25
96.	[redacted]	2014-04-28	2018-01-01	2018-04-27
97.	[redacted]	2014-04-28	2018-01-01	2018-04-27
98.	[redacted]	2014-04-28	2018-01-01	2018-04-27
99.	[redacted]	2014-04-28	2018-01-01	2018-04-27
100.	[redacted]	2014-04-28	2018-01-01	2018-04-27
101.	[redacted]	2014-04-28	2018-01-01	2018-04-27
102.	[redacted]	2014-04-28	2018-01-01	2018-04-27
103.	[redacted]	2014-04-28	2018-01-01	2018-04-27
104.	[redacted]	2014-04-28	2018-01-01	2018-04-27
105.	[redacted]	2014-05-26	2018-01-01	2018-04-29
106.	[redacted]	2014-05-26	2018-01-01	2018-04-29
107.	[redacted]	2014-05-26	2018-01-01	2018-04-29
108.	[redacted]	2014-05-02	2018-01-01	2018-05-01
109.	[redacted]	2014-05-02	2018-01-01	2018-05-01
110.	[redacted]	2015-05-02	2018-01-01	2018-05-01

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
111.	[redacted]	2014-05-26	2018-01-01	2018-05-06
112.		2015-03-23	2018-01-01	2018-05-10
113.		2017-10-04	2018-01-01	2018-05-10
114.		2014-05-26	2018-01-01	2018-05-13
115.		2016-06-17	2018-08-20	2018-12-31
116.		2015-05-16	2018-01-01	2018-05-15
117.		2014-05-26	2018-01-01	2018-05-25
118.		2014-05-26	2018-01-01	2018-05-25
119.		2014-05-26	2018-01-01	2018-05-25
120.		2014-05-26	2018-01-01	2018-05-25
121.		2014-05-26	2018-01-01	2018-05-25
122.		2014-05-26	2018-01-01	2018-05-25
123.		2014-05-26	2018-01-01	2018-05-25
124.		2014-05-26	2018-01-01	2018-05-25
125.		2014-05-26	2018-01-01	2018-05-25
126.		2014-05-26	2018-01-01	2018-05-25
127.		2014-05-26	2018-01-01	2018-05-25
128.		2014-05-26	2018-01-01	2018-05-25
129.		2014-05-26	2018-01-01	2018-05-25
130.		2014-05-26	2018-01-01	2018-05-25
131.		2015-05-26	2018-01-01	2018-05-25
132.		2015-05-26	2018-01-01	2018-05-25
133.		2017-10-19	2018-01-01	2018-06-06
134.		2014-06-10	2018-01-01	2018-06-09
135.		2014-06-11	2018-01-01	2018-06-10
136.		2016-02-02	2018-07-03	2018-12-23
137.		2014-06-25	2018-01-01	2018-06-24
138.		2014-06-25	2018-01-01	2018-06-24
139.		2015-07-13	2018-01-01	2018-06-25
140.		2016-02-02	2018-07-03	2018-12-31
141.		2016-02-02	2018-01-01	2018-07-02
142.		2015-07-13	2018-01-02	2018-07-12
143.		2015-07-13	2018-01-01	2018-07-12
144.		2015-07-13	2018-01-01	2018-07-12
145.		2015-07-13	2018-01-01	2018-07-12
146.		2015-07-13	2018-01-01	2018-07-12
147.		2015-07-13	2018-01-01	2018-07-12
148.		2015-07-13	2018-01-01	2018-07-12
149.		2015-07-13	2018-01-01	2018-07-12
150.		2015-07-13	2018-01-01	2018-07-12
151.		2015-07-13	2018-01-01	2018-07-12
152.		2015-07-13	2018-01-01	2018-07-12
153.		2015-07-13	2018-01-01	2018-07-12
154.		2015-07-13	2018-01-01	2018-07-12
155.		2015-07-13	2018-01-01	2018-07-12
156.		2015-07-13	2018-01-01	2018-07-12
157.		2015-07-13	2018-01-01	2018-07-12
158.		2015-07-13	2018-01-01	2018-07-12
159.		2015-07-13	2018-01-01	2018-07-12
160.		2015-07-13	2018-01-01	2018-07-12
161.		2015-07-13	2018-01-01	2018-07-12
162.		2015-07-13	2018-01-01	2018-07-12
163.		2015-07-13	2018-01-01	2018-07-12

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
164.	[redacted]	2015-07-13	2018-01-01	2018-07-12
165.	[redacted]	2015-07-13	2018-01-01	2018-07-12
166.	[redacted]	2015-07-13	2018-01-01	2018-07-12
167.	[redacted]	2015-07-13	2018-01-01	2018-07-12
168.	[redacted]	2015-07-13	2018-01-01	2018-07-12
169.	[redacted]	2015-07-13	2018-01-01	2018-07-12
170.	[redacted]	2015-07-13	2018-01-01	2018-07-12
171.	[redacted]	2015-07-13	2018-01-01	2018-07-12
172.	[redacted]	2015-07-13	2018-01-01	2018-07-12
173.	[redacted]	2015-07-13	2018-01-01	2018-07-12
174.	[redacted]	2015-07-13	2018-01-01	2018-07-12
175.	[redacted]	2015-07-13	2018-01-01	2018-07-12
176.	[redacted]	2015-07-13	2018-01-01	2018-07-12
177.	[redacted]	2015-07-13	2018-01-01	2018-07-12
178.	[redacted]	2015-07-13	2018-01-01	2018-07-12
179.	[redacted]	2015-07-13	2018-01-01	2018-07-12
180.	[redacted]	2015-07-13	2018-01-01	2018-07-12
181.	[redacted]	2015-07-13	2018-01-01	2018-07-12
182.	[redacted]	2015-07-13	2018-01-01	2018-07-12
183.	[redacted]	2015-07-13	2018-01-01	2018-07-12
184.	[redacted]	2015-07-28	2018-01-01	2018-07-27
185.	[redacted]	2015-10-13	2018-01-01	2018-07-29
186.	[redacted]	2015-03-23	2018-01-01	2018-08-01
187.	[redacted]	2016-05-02	2018-01-01	2018-08-13
188.	[redacted]	2016-02-02	2018-01-01	2018-08-19
189.	[redacted]	2015-09-08	2018-01-01	2018-09-07
190.	[redacted]	2016-01-08	2018-01-01	2018-09-11
191.	[redacted]	2017-06-22	2018-01-01	2018-09-24
192.	[redacted]	2016-02-02	2018-01-01	2018-09-30
193.	[redacted]	2015-04-16	2018-01-01	2018-10-09
194.	[redacted]	2015-04-16	2018-01-01	2018-10-11
195.	[redacted]	2015-10-13	2018-01-01	2018-10-12
196.	[redacted]	2015-10-13	2018-01-01	2018-10-12
197.	[redacted]	2015-10-13	2018-01-01	2018-10-12
198.	[redacted]	2015-10-13	2018-01-01	2018-10-12
199.	[redacted]	2015-10-13	2018-01-01	2018-10-12
200.	[redacted]	2015-10-13	2018-01-01	2018-10-12
201.	[redacted]	2015-10-13	2018-01-01	2018-10-12
202.	[redacted]	2015-10-13	2018-01-01	2018-10-12
203.	[redacted]	2015-10-13	2018-01-01	2018-10-12
204.	[redacted]	2015-10-13	2018-01-01	2018-10-12
205.	[redacted]	2015-10-13	2018-01-01	2018-10-12
206.	[redacted]	2015-10-13	2018-01-01	2018-10-12
207.	[redacted]	2015-10-13	2018-01-01	2018-10-12
208.	[redacted]	2015-10-13	2018-01-01	2018-10-12
209.	[redacted]	2015-10-13	2018-01-01	2018-10-12
210.	[redacted]	2015-03-19	2018-01-01	2018-10-15
211.	[redacted]	2016-09-21	2018-03-19	2018-12-31
212.	[redacted]	2015-03-19	2018-01-01	2018-10-17
213.	[redacted]	2015-04-16	2018-01-01	2018-10-24
214.	[redacted]	2015-03-19	2018-01-01	2018-10-28
215.	[redacted]	2015-04-16	2018-01-01	2018-10-30
216.	[redacted]	2015-04-16	2018-01-01	2018-11-04

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
217.	[redacted]	2015-04-02	2018-01-01	2018-11-12
218.	[redacted]	2016-04-05	2018-01-01	2018-11-28
219.	[redacted]	2015-03-23	2018-01-01	2018-12-05
220.	[redacted]	2016-05-10	2018-01-01	2018-12-10
221.	[redacted]	2014-12-15	2018-01-01	2018-12-14
222.	[redacted]	2014-12-15	2018-01-01	2018-12-14
223.	[redacted]	2014-12-15	2018-01-01	2018-12-14
224.	[redacted]	2014-12-15	2018-01-01	2018-12-14
225.	[redacted]	2014-12-15	2018-01-01	2018-12-14
226.	[redacted]	2015-12-21	2018-01-01	2018-12-20
227.	[redacted]	2015-04-16	2018-01-01	2018-12-25
228.	[redacted]	2015-03-19	2018-01-02	2018-12-31
229.	[redacted]	2016-04-05	2018-01-01	2018-12-31
230.	[redacted]	2017-05-06	2018-01-01	2018-12-31
231.	[redacted]	2016-02-02	2018-01-01	2018-12-31
232.	[redacted]	2017-06-08	2018-01-01	2018-12-31
233.	[redacted]	2016-02-02	2018-01-01	2018-12-31
234.	[redacted]	2017-08-05	2018-01-01	2018-12-31
235.	[redacted]	2017-05-06	2018-01-01	2018-12-31
236.	[redacted]	2015-04-16	2018-01-01	2018-12-31
237.	[redacted]	2017-06-20	2018-01-01	2018-12-31
238.	[redacted]	2016-06-17	2018-01-01	2018-12-31
239.	[redacted]	2017-02-03	2018-01-01	2018-12-31
240.	[redacted]	2017-06-08	2018-01-01	2018-12-31
241.	[redacted]	2016-04-28	2018-01-01	2018-12-31
242.	[redacted]	2015-04-16	2018-01-01	2018-12-31
243.	[redacted]	2015-04-16	2018-01-01	2018-12-31
244.	[redacted]	2015-04-16	2018-01-01	2018-12-31
245.	[redacted]	2017-10-11	2018-01-01	2018-12-31
246.	[redacted]	2015-03-23	2018-01-01	2018-12-31
247.	[redacted]	2016-04-05	2018-01-01	2018-12-31
248.	[redacted]	2015-04-16	2018-01-01	2018-12-31
249.	[redacted]	2015-04-16	2018-01-01	2018-12-31
250.	[redacted]	2017-02-03	2018-01-01	2018-12-31
251.	[redacted]	2017-09-02	2018-01-01	2018-12-31
252.	[redacted]	2016-04-05	2018-01-01	2018-12-31
253.	[redacted]	2016-05-24	2018-01-01	2018-12-31
254.	[redacted]	2017-05-06	2018-01-01	2018-12-31
255.	[redacted]	2016-06-17	2018-01-01	2018-12-31
256.	[redacted]	2015-03-23	2018-01-01	2018-12-31
257.	[redacted]	2017-05-25	2018-01-01	2018-12-31
258.	[redacted]	2016-05-24	2018-01-01	2018-12-31
259.	[redacted]	2017-04-27	2018-01-01	2018-12-31
260.	[redacted]	2015-03-19	2018-01-01	2018-12-31
261.	[redacted]	2015-03-19	2018-01-01	2018-12-31
262.	[redacted]	2015-03-19	2018-01-01	2018-12-31
263.	[redacted]	2015-03-19	2018-01-01	2018-12-31
264.	[redacted]	2015-03-19	2018-01-01	2018-12-31
265.	[redacted]	2015-03-19	2018-01-01	2018-12-31
266.	[redacted]	2015-03-19	2018-01-01	2018-12-31
267.	[redacted]	2015-03-19	2018-01-01	2018-12-31
268.	[redacted]	2015-03-19	2018-01-01	2018-12-31
269.	[redacted]	2015-03-19	2018-01-01	2018-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
270.	[redacted]	2015-03-19	2018-01-01	2018-12-31
271.		2015-03-19	2018-01-01	2018-12-31
272.		2015-04-16	2018-01-01	2018-12-31
273.		2015-04-16	2018-01-01	2018-12-31
274.		2015-04-16	2018-01-01	2018-12-31
275.		2015-04-16	2018-01-01	2018-12-31
276.		2015-04-16	2018-01-01	2018-12-31
277.		2015-04-16	2018-01-01	2018-12-31
278.		2015-04-16	2018-01-01	2018-12-31
279.		2015-04-16	2018-01-01	2018-12-31
280.		2015-04-16	2018-01-01	2018-12-31
281.		2015-04-16	2018-01-01	2018-12-31
282.		2015-04-16	2018-01-01	2018-12-31
283.		2015-04-16	2018-01-01	2018-12-31
284.		2015-04-16	2018-01-01	2018-12-31
285.		2015-04-16	2018-01-01	2018-12-31
286.		2015-04-16	2018-01-01	2018-12-31
287.		2017-05-06	2018-01-01	2018-12-31
288.		2016-06-17	2018-01-01	2018-12-31
289.		2017-04-27	2018-01-01	2018-12-31
290.		2016-02-09	2018-01-01	2018-12-31
291.		2016-02-05	2018-01-01	2018-12-31
292.		2016-02-05	2018-01-01	2018-12-31
293.		2016-02-10	2018-01-01	2018-12-31
294.		2016-02-02	2018-01-01	2018-12-31
295.		2016-02-02	2018-01-01	2018-12-31
296.		2016-02-02	2018-01-01	2018-12-31
297.		2016-02-02	2018-01-01	2018-12-31
298.		2016-02-02	2018-01-01	2018-12-31
299.		2016-02-02	2018-01-01	2018-12-31
300.		2016-02-02	2018-01-01	2018-12-31
301.		2016-02-02	2018-01-01	2018-12-31
302.		2016-02-02	2018-01-01	2018-12-31
303.		2016-02-02	2018-01-01	2018-12-31
304.		2016-02-02	2018-01-01	2018-12-31
305.		2016-02-02	2018-01-01	2018-12-31
306.		2016-06-17	2018-01-01	2018-12-31
307.		2016-04-05	2018-01-01	2018-12-31
308.		2016-04-05	2018-01-01	2018-12-31
309.		2016-04-05	2018-01-01	2018-12-31
310.		2016-04-05	2018-01-01	2018-12-31
311.		2016-04-05	2018-01-01	2018-12-31
312.		2016-04-05	2018-01-01	2018-12-31
313.		2016-04-05	2018-01-01	2018-12-31
314.		2016-04-05	2018-01-01	2018-12-31
315.		2016-04-05	2018-01-01	2018-12-31
316.		2016-04-05	2018-01-01	2018-12-31
317.		2016-04-05	2018-01-01	2018-12-31
318.		2016-04-05	2018-01-01	2018-12-31
319.		2016-05-02	2018-01-01	2018-12-31
320.		2016-05-02	2018-01-01	2018-12-31
321.		2016-05-02	2018-01-01	2018-12-31
322.		2016-05-02	2018-01-01	2018-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
323.	[redacted]	2016-05-25	2018-01-01	2018-12-31
324.	[redacted]	2016-05-02	2018-01-01	2018-12-31
325.	[redacted]	2016-03-14	2018-01-01	2018-12-31
326.	[redacted]	2016-02-05	2018-01-01	2018-12-31
327.	[redacted]	2016-05-02	2018-01-01	2018-12-31
328.	[redacted]	2016-05-02	2018-01-01	2018-12-31
329.	[redacted]	2016-05-02	2018-01-01	2018-12-31
330.	[redacted]	2016-05-25	2018-01-01	2018-12-31
331.	[redacted]	2016-02-25	2018-01-01	2018-12-31
332.	[redacted]	2016-04-28	2018-01-01	2018-12-31
333.	[redacted]	2016-04-28	2018-01-01	2018-12-31
334.	[redacted]	2016-04-28	2018-01-01	2018-12-31
335.	[redacted]	2016-04-28	2018-01-01	2018-12-31
336.	[redacted]	2016-04-28	2018-01-01	2018-12-31
337.	[redacted]	2016-04-28	2018-01-01	2018-12-31
338.	[redacted]	2016-04-28	2018-01-01	2018-12-31
339.	[redacted]	2016-04-28	2018-01-01	2018-12-31
340.	[redacted]	2016-04-28	2018-01-01	2018-12-31
341.	[redacted]	2016-04-28	2018-01-01	2018-12-31
342.	[redacted]	2016-04-28	2018-01-01	2018-12-31
343.	[redacted]	2016-04-28	2018-01-01	2018-12-31
344.	[redacted]	2016-04-28	2018-01-01	2018-12-31
345.	[redacted]	2016-04-28	2018-01-01	2018-12-31
346.	[redacted]	2016-05-25	2018-01-01	2018-12-31
347.	[redacted]	2016-05-24	2018-01-01	2018-12-31
348.	[redacted]	2016-05-24	2018-01-01	2018-12-31
349.	[redacted]	2016-05-24	2018-01-01	2018-12-31
350.	[redacted]	2016-05-24	2018-01-01	2018-12-31
351.	[redacted]	2016-05-24	2018-01-01	2018-12-31
352.	[redacted]	2016-05-24	2018-01-01	2018-12-31
353.	[redacted]	2016-05-24	2018-01-01	2018-12-31
354.	[redacted]	2016-05-24	2018-01-01	2018-12-31
355.	[redacted]	2016-05-24	2018-01-01	2018-12-31
356.	[redacted]	2016-05-24	2018-01-01	2018-12-31
357.	[redacted]	2016-05-24	2018-01-01	2018-12-31
358.	[redacted]	2016-05-24	2018-01-01	2018-12-31
359.	[redacted]	2016-05-24	2018-01-01	2018-12-31
360.	[redacted]	2016-06-17	2018-01-01	2018-12-31
361.	[redacted]	2016-06-17	2018-01-01	2018-12-31
362.	[redacted]	2016-06-17	2018-01-01	2018-12-31
363.	[redacted]	2016-06-17	2018-01-01	2018-12-31
364.	[redacted]	2016-06-17	2018-01-01	2018-12-31
365.	[redacted]	2016-06-17	2018-01-01	2018-12-31
366.	[redacted]	2016-06-17	2018-01-01	2018-12-31
367.	[redacted]	2017-04-27	2018-01-01	2018-12-31
368.	[redacted]	2016-06-17	2018-01-01	2018-12-31
369.	[redacted]	2016-06-17	2018-01-01	2018-12-31
370.	[redacted]	2016-06-17	2018-01-01	2018-12-31
371.	[redacted]	2016-06-17	2018-01-01	2018-12-31
372.	[redacted]	2016-06-17	2018-01-01	2018-12-31
373.	[redacted]	2016-06-17	2018-01-01	2018-12-31
374.	[redacted]	2016-06-17	2018-01-01	2018-12-31
375.	[redacted]	2016-06-17	2018-01-01	2018-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
376.	[redacted]	2016-06-17	2018-01-01	2018-12-31
377.		2016-06-17	2018-01-01	2018-12-31
378.		2016-06-17	2018-01-01	2018-12-31
379.		2016-06-17	2018-01-01	2018-12-31
380.		2016-06-17	2018-01-01	2018-12-31
381.		2016-06-17	2018-01-01	2018-12-31
382.		2016-06-17	2018-01-01	2018-12-31
383.		2016-06-17	2018-01-01	2018-12-31
384.		2016-06-17	2018-01-01	2018-12-31
385.		2016-06-17	2018-01-01	2018-12-31
386.		2016-06-17	2018-01-01	2018-12-31
387.		2016-06-17	2018-01-01	2018-12-31
388.		2016-06-17	2018-01-01	2018-12-31
389.		2016-06-17	2018-01-01	2018-12-31
390.		2016-06-17	2018-01-01	2018-12-31
391.		2016-06-17	2018-01-01	2018-12-31
392.		2016-06-17	2018-01-01	2018-12-31
393.		2017-02-03	2018-01-01	2018-12-31
394.		2017-04-27	2018-01-01	2018-12-31
395.		2016-12-01	2018-01-01	2018-12-31
396.		2017-08-05	2018-01-01	2018-12-31
397.		2017-06-08	2018-01-01	2018-12-31
398.		2017-01-23	2018-01-01	2018-12-31
399.		2016-11-18	2018-01-01	2018-12-31
400.		2016-02-02	2018-01-01	2018-12-31
401.		2016-07-08	2018-01-01	2018-12-31
402.		2016-10-27	2018-01-01	2018-12-31
403.		2016-12-01	2018-01-01	2018-12-31
404.		2016-12-01	2018-01-01	2018-12-31
405.		2016-12-01	2018-01-01	2018-12-31
406.		2016-12-01	2018-01-01	2018-12-31
407.		2016-12-01	2018-01-01	2018-12-31
408.		2016-12-01	2018-01-01	2018-12-31
409.		2016-12-01	2018-01-01	2018-12-31
410.		2016-12-01	2018-01-01	2018-12-31
411.		2016-12-01	2018-01-01	2018-12-31
412.		2016-12-01	2018-01-01	2018-12-31
413.		2016-12-01	2018-01-01	2018-12-31
414.		2016-12-01	2018-01-01	2018-12-31
415.		2016-12-01	2018-01-01	2018-12-31
416.		2017-01-23	2018-01-01	2018-12-31
417.		2017-01-23	2018-01-01	2018-12-31
418.		2017-01-23	2018-01-01	2018-12-31
419.		2017-01-23	2018-01-01	2018-12-31
420.		2017-01-23	2018-01-01	2018-12-31
421.		2017-01-23	2018-01-01	2018-12-31
422.		2017-01-23	2018-01-01	2018-12-31
423.		2017-01-23	2018-01-01	2018-12-31
424.		2017-01-23	2018-01-01	2018-12-31
425.		2017-01-23	2018-01-01	2018-12-31
426.		2017-01-23	2018-01-01	2018-12-31
427.		2017-01-23	2018-01-01	2018-12-31
428.		2017-01-24	2018-01-01	2018-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
429.	[redacted]	2017-01-24	2018-01-01	2018-12-31
430.	[redacted]	2017-01-24	2018-01-01	2018-12-31
431.	[redacted]	2017-01-24	2018-01-01	2018-12-31
432.	[redacted]	2017-01-24	2018-01-01	2018-12-31
433.	[redacted]	2017-01-24	2018-01-01	2018-12-31
434.	[redacted]	2017-09-02	2018-01-01	2018-12-31
435.	[redacted]	2017-09-02	2018-01-01	2018-12-31
436.	[redacted]	2017-09-02	2018-01-01	2018-12-31
437.	[redacted]	2017-09-02	2018-01-01	2018-12-31
438.	[redacted]	2017-09-02	2018-01-01	2018-12-31
439.	[redacted]	2017-09-02	2018-01-01	2018-12-31
440.	[redacted]	2017-09-02	2018-01-01	2018-12-31
441.	[redacted]	2017-09-02	2018-01-01	2018-12-31
442.	[redacted]	2017-09-02	2018-01-01	2018-12-31
443.	[redacted]	2017-09-02	2018-01-01	2018-12-31
444.	[redacted]	2017-09-02	2018-01-01	2018-12-31
445.	[redacted]	2017-09-02	2018-01-01	2018-12-31
446.	[redacted]	2017-09-02	2018-01-01	2018-12-31
447.	[redacted]	2017-09-02	2018-01-01	2018-12-31
448.	[redacted]	2017-09-02	2018-01-01	2018-12-31
449.	[redacted]	2017-08-14	2018-01-01	2018-12-31
450.	[redacted]	2017-02-03	2018-01-01	2018-12-31
451.	[redacted]	2017-02-03	2018-01-01	2018-12-31
452.	[redacted]	2017-02-03	2018-01-01	2018-12-31
453.	[redacted]	2017-02-03	2018-01-01	2018-12-31
454.	[redacted]	2017-02-03	2018-01-01	2018-12-31
455.	[redacted]	2017-02-03	2018-01-01	2018-12-31
456.	[redacted]	2017-02-03	2018-01-01	2018-12-31
457.	[redacted]	2017-02-03	2018-01-01	2018-12-31
458.	[redacted]	2017-02-03	2018-01-01	2018-12-31
459.	[redacted]	2017-02-03	2018-01-01	2018-12-31
460.	[redacted]	2017-02-03	2018-01-01	2018-12-31
461.	[redacted]	2017-03-02	2018-01-01	2018-12-31
462.	[redacted]	2017-02-03	2018-01-01	2018-12-31
463.	[redacted]	2017-02-03	2018-01-01	2018-12-31
464.	[redacted]	2017-03-21	2018-01-01	2018-12-31
465.	[redacted]	2017-03-23	2018-01-01	2018-12-31
466.	[redacted]	2017-03-21	2018-01-01	2018-12-31
467.	[redacted]	2016-02-08	2018-01-01	2018-12-31
468.	[redacted]	2017-03-21	2018-01-01	2018-12-31
469.	[redacted]	2017-02-16	2018-01-01	2018-12-31
470.	[redacted]	2017-03-23	2018-01-01	2018-12-31
471.	[redacted]	2017-03-23	2018-01-01	2018-12-31
472.	[redacted]	2016-02-16	2018-01-01	2018-12-31
473.	[redacted]	2017-03-23	2018-01-01	2018-12-31
474.	[redacted]	2017-03-23	2018-01-01	2018-12-31
475.	[redacted]	2017-03-23	2018-01-01	2018-12-31
476.	[redacted]	2017-03-23	2018-01-01	2018-12-31
477.	[redacted]	2017-03-23	2018-01-01	2018-12-31
478.	[redacted]	2017-03-23	2018-01-01	2018-12-31
479.	[redacted]	2017-03-23	2018-01-01	2018-12-31
480.	[redacted]	2017-03-23	2018-01-01	2018-12-31
481.	[redacted]	2017-03-23	2018-01-01	2018-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
482.	[redacted]	2017-03-23	2018-01-01	2018-12-31
483.		2017-03-23	2018-01-01	2018-12-31
484.		2017-03-23	2018-01-01	2018-12-31
485.		2017-03-23	2018-01-01	2018-12-31
486.		2017-03-23	2018-01-01	2018-12-31
487.		2017-04-27	2018-01-01	2018-12-31
488.		2017-04-27	2018-01-01	2018-12-31
489.		2017-04-27	2018-01-01	2018-12-31
490.		2017-04-27	2018-01-01	2018-12-31
491.		2017-04-27	2018-01-01	2018-12-31
492.		2017-04-27	2018-01-01	2018-12-31
493.		2017-04-27	2018-01-01	2018-12-31
494.		2017-04-27	2018-01-01	2018-12-31
495.		2017-04-27	2018-01-01	2018-12-31
496.		2017-04-27	2018-01-01	2018-12-31
497.		2017-08-05	2018-01-01	2018-12-31
498.		2017-08-05	2018-01-01	2018-12-31
499.		2017-08-05	2018-01-01	2018-12-31
500.		2017-08-05	2018-01-01	2018-12-31
501.		2017-08-05	2018-01-01	2018-12-31
502.		2017-08-05	2018-01-01	2018-12-31
503.		2017-08-05	2018-01-01	2018-12-31
504.		2017-08-05	2018-01-01	2018-12-31
505.		2017-08-05	2018-01-01	2018-12-31
506.		2017-08-05	2018-01-01	2018-12-31
507.		2017-08-05	2018-01-01	2018-12-31
508.		2017-08-05	2018-01-01	2018-12-31
509.		2017-08-05	2018-01-01	2018-12-31
510.		2017-08-05	2018-01-01	2018-12-31
511.		2017-06-20	2018-01-01	2018-12-31
512.		2017-06-13	2018-01-01	2018-12-31
513.		2017-06-22	2018-01-01	2018-12-31
514.		2017-06-13	2018-01-01	2018-12-31
515.		2017-06-13	2018-01-01	2018-12-31
516.		2017-06-13	2018-01-01	2018-12-31
517.		2017-06-20	2018-01-01	2018-12-31
518.		2017-06-22	2018-01-01	2018-12-31
519.		2017-06-13	2018-01-01	2018-12-31
520.		2017-05-06	2018-01-01	2018-12-31
521.		2017-05-06	2018-01-01	2018-12-31
522.		2017-05-06	2018-01-01	2018-12-31
523.		2017-05-06	2018-01-01	2018-12-31
524.		2017-05-06	2018-01-01	2018-12-31
525.		2017-05-06	2018-01-01	2018-12-31
526.		2017-05-06	2018-01-01	2018-12-31
527.		2017-05-06	2018-01-01	2018-12-31
528.		2017-05-06	2018-01-01	2018-12-31
529.		2017-05-06	2018-01-01	2018-12-31
530.		2017-05-06	2018-01-01	2018-12-31
531.		2017-05-06	2018-01-01	2018-12-31
532.		2017-06-08	2018-01-01	2018-12-31
533.		2017-06-08	2018-01-01	2018-12-31
534.		2017-06-08	2018-01-01	2018-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
535.	[redacted]	2017-06-08	2018-01-01	2018-12-31
536.		2017-06-08	2018-01-01	2018-12-31
537.		2017-06-08	2018-01-01	2018-12-31
538.		2017-06-08	2018-01-01	2018-12-31
539.		2017-06-08	2018-01-01	2018-12-31
540.		2017-06-08	2018-01-01	2018-12-31
541.		2017-06-08	2018-01-01	2018-12-31
542.		2017-06-08	2018-01-01	2018-12-31
543.		2017-06-08	2018-01-01	2018-12-31
544.		2017-10-20	2018-01-01	2018-12-31
545.		2017-01-24	2018-01-01	2018-12-31
546.		2017-05-23	2018-01-01	2018-12-31
547.		2017-10-05	2018-01-01	2018-12-31
548.		2017-08-28	2018-01-01	2018-12-31
549.		2017-10-17	2018-01-01	2018-12-31
550.		2017-10-19	2018-01-01	2018-12-31
551.		2017-10-19	2018-01-01	2018-12-31
552.		2017-10-04	2018-01-01	2018-12-31
553.		2017-10-20	2018-01-01	2018-12-31
554.		2016-05-25	2018-01-01	2018-12-31
555.		2016-08-22	2018-01-01	2018-12-31
556.		2017-10-11	2018-01-01	2018-12-31
557.		2017-10-06	2018-01-01	2018-12-31
558.		2017-10-19	2018-01-01	2018-12-31
559.		2017-10-11	2018-01-01	2018-12-31
560.		2016-11-18	2018-01-01	2018-12-31
561.		2016-11-18	2018-01-01	2018-12-31
562.		2017-07-16	2018-01-01	2018-12-31
563.		2017-10-19	2018-01-01	2018-12-31
564.		2016-02-05	2018-01-01	2018-12-31
565.		2017-10-08	2018-01-01	2018-12-31
566.		2017-10-06	2018-01-01	2018-12-31

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Ontario apprenticeship training tax credit (continued)

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
1.		31	425
2.	84		2,301
3.	77		2,110
4.		110	1,507
5.		110	1,507
6.	124		3,397
7.	76		2,082
8.	93		2,548
9.	171		4,685
10.	35		959
11.	69		1,890
12.	76		2,082
13.	171		4,685
14.	69		1,890
15.	154		4,219
16.	218		5,973
17.	158		4,329
18.		309	4,233
19.		309	4,233
20.		327	4,479
21.	98		2,685
22.		338	4,630
23.	348		9,534
24.	69		1,890
25.		315	4,315
26.	348		9,534
27.	8		219
28.	9		247
29.	9		247
30.	10		274
31.	12		329
32.	15		411
33.	17		466
34.	21		575
35.	24		658
36.	26		712
37.	26		712
38.	26		712
39.	26		712
40.	26		712
41.	26		712
42.	28		767
43.	35		959
44.	35		959
45.	36		986
46.	37		1,014
47.	37		1,014
48.	43		1,178
49.	44		1,205
50.	44		1,205
51.	44		1,205
52.	54		1,479

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) **442**	**H2** Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) **443**	**I** Maximum credit amount for the tax year (see note 2) **445**
53.	54		1,479
54.	54		1,479
55.	54		1,479
56.	54		1,479
57.	54		1,479
58.	54		1,479
59.	54		1,479
60.	54		1,479
61.	54		1,479
62.	54		1,479
63.	57		1,562
64.	59		1,616
65.	64		1,753
66.	65		1,781
67.	71		1,945
68.	73		2,000
69.	75		2,055
70.	75		2,055
71.	75		2,055
72.	75		2,055
73.	75		2,055
74.	75		2,055
75.	77		2,110
76.	80		2,192
77.	80		2,192
78.		84	1,151
79.	86		2,356
80.		92	1,260
81.	93		2,548
82.	93		2,548
83.	94		2,575
84.		94	1,288
85.		98	1,342
86.	98		2,685
87.	98		2,685
88.	98		2,685
89.	100		2,740
90.		100	1,370
91.	105		2,877
92.		106	1,452
93.		110	1,507
94.	112		3,068
95.	115		3,151
96.	117		3,205
97.	117		3,205
98.	117		3,205
99.	117		3,205
100.	117		3,205
101.	117		3,205
102.	117		3,205
103.	117		3,205
104.	117		3,205
105.	119		3,260
106.	119		3,260

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
107.	119		3,260
108.	121		3,315
109.	121		3,315
110.		121	1,658
111.	126		3,452
112.	130		3,562
113.		130	1,781
114.	133		3,644
115.		134	1,836
116.		135	1,849
117.	145		3,973
118.	145		3,973
119.	145		3,973
120.	145		3,973
121.	145		3,973
122.	145		3,973
123.	145		3,973
124.	145		3,973
125.	145		3,973
126.	145		3,973
127.	145		3,973
128.	145		3,973
129.	145		3,973
130.	145		3,973
131.		145	1,986
132.		145	1,986
133.		157	2,151
134.	160		4,384
135.	161		4,411
136.		174	2,384
137.	175		4,795
138.	175		4,795
139.		176	2,411
140.		182	2,493
141.		183	2,507
142.		192	2,630
143.		193	2,644
144.		193	2,644
145.		193	2,644
146.		193	2,644
147.		193	2,644
148.		193	2,644
149.		193	2,644
150.		193	2,644
151.		193	2,644
152.		193	2,644
153.		193	2,644
154.		193	2,644
155.		193	2,644
156.		193	2,644
157.		193	2,644
158.		193	2,644
159.		193	2,644
160.		193	2,644

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
161.		193	2,644
162.		193	2,644
163.		193	2,644
164.		193	2,644
165.		193	2,644
166.		193	2,644
167.		193	2,644
168.		193	2,644
169.		193	2,644
170.		193	2,644
171.		193	2,644
172.		193	2,644
173.		193	2,644
174.		193	2,644
175.		193	2,644
176.		193	2,644
177.		193	2,644
178.		193	2,644
179.		193	2,644
180.		193	2,644
181.		193	2,644
182.		193	2,644
183.		193	2,644
184.		208	2,849
185.		210	2,877
186.	213		5,836
187.		225	3,082
188.		231	3,164
189.		250	3,425
190.		254	3,479
191.		267	3,658
192.		273	3,740
193.	282		7,726
194.	284		7,781
195.		285	3,904
196.		285	3,904
197.		285	3,904
198.		285	3,904
199.		285	3,904
200.		285	3,904
201.		285	3,904
202.		285	3,904
203.		285	3,904
204.		285	3,904
205.		285	3,904
206.		285	3,904
207.		285	3,904
208.		285	3,904
209.		285	3,904
210.	288		7,890
211.		288	3,945
212.	290		7,945
213.	297		8,137
214.	301		8,247

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
215.	303		8,301
216.	308		8,438
217.	316		8,658
218.		332	4,548
219.	339		9,288
220.		344	4,712
221.	348		9,534
222.	348		9,534
223.	348		9,534
224.	348		9,534
225.	348		9,534
226.		354	4,849
227.	359		9,836
228.	364		9,973
229.		365	5,000
230.		365	5,000
231.		365	5,000
232.		365	5,000
233.		365	5,000
234.		365	5,000
235.		365	5,000
236.	365		10,000
237.		365	5,000
238.		365	5,000
239.		365	5,000
240.		365	5,000
241.		365	5,000
242.	365		10,000
243.	365		10,000
244.	365		10,000
245.		365	5,000
246.	365		10,000
247.		365	5,000
248.	365		10,000
249.	365		10,000
250.		365	5,000
251.		365	5,000
252.		365	5,000
253.		365	5,000
254.		365	5,000
255.		365	5,000
256.	365		10,000
257.		365	5,000
258.		365	5,000
259.		365	5,000
260.	365		10,000
261.	365		10,000
262.	365		10,000
263.	365		10,000
264.	365		10,000
265.	365		10,000
266.	365		10,000
267.	365		10,000
268.	365		10,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
269.	365		10,000
270.	365		10,000
271.	365		10,000
272.	365		10,000
273.	365		10,000
274.	365		10,000
275.	365		10,000
276.	365		10,000
277.	365		10,000
278.	365		10,000
279.	365		10,000
280.	365		10,000
281.	365		10,000
282.	365		10,000
283.	365		10,000
284.	365		10,000
285.	365		10,000
286.	365		10,000
287.		365	5,000
288.		365	5,000
289.		365	5,000
290.		365	5,000
291.		365	5,000
292.		365	5,000
293.		365	5,000
294.		365	5,000
295.		365	5,000
296.		365	5,000
297.		365	5,000
298.		365	5,000
299.		365	5,000
300.		365	5,000
301.		365	5,000
302.		365	5,000
303.		365	5,000
304.		365	5,000
305.		365	5,000
306.		365	5,000
307.		365	5,000
308.		365	5,000
309.		365	5,000
310.		365	5,000
311.		365	5,000
312.		365	5,000
313.		365	5,000
314.		365	5,000
315.		365	5,000
316.		365	5,000
317.		365	5,000
318.		365	5,000
319.		365	5,000
320.		365	5,000
321.		365	5,000
322.		365	5,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
323.		365	5,000
324.		365	5,000
325.		365	5,000
326.		365	5,000
327.		365	5,000
328.		365	5,000
329.		365	5,000
330.		365	5,000
331.		365	5,000
332.		365	5,000
333.		365	5,000
334.		365	5,000
335.		365	5,000
336.		365	5,000
337.		365	5,000
338.		365	5,000
339.		365	5,000
340.		365	5,000
341.		365	5,000
342.		365	5,000
343.		365	5,000
344.		365	5,000
345.		365	5,000
346.		365	5,000
347.		365	5,000
348.		365	5,000
349.		365	5,000
350.		365	5,000
351.		365	5,000
352.		365	5,000
353.		365	5,000
354.		365	5,000
355.		365	5,000
356.		365	5,000
357.		365	5,000
358.		365	5,000
359.		365	5,000
360.		365	5,000
361.		365	5,000
362.		365	5,000
363.		365	5,000
364.		365	5,000
365.		365	5,000
366.		365	5,000
367.		365	5,000
368.		365	5,000
369.		365	5,000
370.		365	5,000
371.		365	5,000
372.		365	5,000
373.		365	5,000
374.		365	5,000
375.		365	5,000
376.		365	5,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
377.		365	5,000
378.		365	5,000
379.		365	5,000
380.		365	5,000
381.		365	5,000
382.		365	5,000
383.		365	5,000
384.		365	5,000
385.		365	5,000
386.		365	5,000
387.		365	5,000
388.		365	5,000
389.		365	5,000
390.		365	5,000
391.		365	5,000
392.		365	5,000
393.		365	5,000
394.		365	5,000
395.		365	5,000
396.		365	5,000
397.		365	5,000
398.		365	5,000
399.		365	5,000
400.		365	5,000
401.		365	5,000
402.		365	5,000
403.		365	5,000
404.		365	5,000
405.		365	5,000
406.		365	5,000
407.		365	5,000
408.		365	5,000
409.		365	5,000
410.		365	5,000
411.		365	5,000
412.		365	5,000
413.		365	5,000
414.		365	5,000
415.		365	5,000
416.		365	5,000
417.		365	5,000
418.		365	5,000
419.		365	5,000
420.		365	5,000
421.		365	5,000
422.		365	5,000
423.		365	5,000
424.		365	5,000
425.		365	5,000
426.		365	5,000
427.		365	5,000
428.		365	5,000
429.		365	5,000
430.		365	5,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
431.		365	5,000
432.		365	5,000
433.		365	5,000
434.		365	5,000
435.		365	5,000
436.		365	5,000
437.		365	5,000
438.		365	5,000
439.		365	5,000
440.		365	5,000
441.		365	5,000
442.		365	5,000
443.		365	5,000
444.		365	5,000
445.		365	5,000
446.		365	5,000
447.		365	5,000
448.		365	5,000
449.		365	5,000
450.		365	5,000
451.		365	5,000
452.		365	5,000
453.		365	5,000
454.		365	5,000
455.		365	5,000
456.		365	5,000
457.		365	5,000
458.		365	5,000
459.		365	5,000
460.		365	5,000
461.		365	5,000
462.		365	5,000
463.		365	5,000
464.		365	5,000
465.		365	5,000
466.		365	5,000
467.		365	5,000
468.		365	5,000
469.		365	5,000
470.		365	5,000
471.		365	5,000
472.		365	5,000
473.		365	5,000
474.		365	5,000
475.		365	5,000
476.		365	5,000
477.		365	5,000
478.		365	5,000
479.		365	5,000
480.		365	5,000
481.		365	5,000
482.		365	5,000
483.		365	5,000
484.		365	5,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
485.		365	5,000
486.		365	5,000
487.		365	5,000
488.		365	5,000
489.		365	5,000
490.		365	5,000
491.		365	5,000
492.		365	5,000
493.		365	5,000
494.		365	5,000
495.		365	5,000
496.		365	5,000
497.		365	5,000
498.		365	5,000
499.		365	5,000
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501.		365	5,000
502.		365	5,000
503.		365	5,000
504.		365	5,000
505.		365	5,000
506.		365	5,000
507.		365	5,000
508.		365	5,000
509.		365	5,000
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528.		365	5,000
529.		365	5,000
530.		365	5,000
531.		365	5,000
532.		365	5,000
533.		365	5,000
534.		365	5,000
535.		365	5,000
536.		365	5,000
537.		365	5,000
538.		365	5,000

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
539.		365	5,000
540.		365	5,000
541.		365	5,000
542.		365	5,000
543.		365	5,000
544.		365	5,000
545.		365	5,000
546.		365	5,000
547.		365	5,000
548.		365	5,000
549.		365	5,000
550.		365	5,000
551.		365	5,000
552.		365	5,000
553.		365	5,000
554.		365	5,000
555.		365	5,000
556.		365	5,000
557.		365	5,000
558.		365	5,000
559.		365	5,000
560.		365	5,000
561.		365	5,000
562.		365	5,000
563.		365	5,000
564.		365	5,000
565.		365	5,000
566.		365	5,000

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*****) or ($5,000 × H2/365*****), whichever applies.
***** 366 days, if the tax year includes February 29

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
1.		61,288	15,322
2.	68,025		23,809
3.	61,658		21,580
4.		13,183	3,296
5.		16,078	4,020
6.	95,052		33,268
7.	45,125		15,794
8.	59,045		20,666
9.	76,444		26,755
10.	16,027		5,609
11.	27,833		9,742
12.	31,378		10,982
13.	69,215		24,225
14.	25,590		8,957

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
15.	69,829		24,440
16.	66,498		23,274
17.	50,853		17,799
18.		38,700	9,675
19.		39,648	9,912
20.		36,160	9,040
21.	21,605		7,562
22.		59,515	14,879
23.	60,931		21,326
24.	14,032		4,911
25.		70,055	17,514
26.	53,943		18,880
27.	2,864		1,002
28.	2,901		1,015
29.	2,645		926
30.	2,921		1,022
31.	1,686		590
32.	4,472		1,565
33.	5,720		2,002
34.	5,948		2,082
35.	7,068		2,474
36.	7,485		2,620
37.	7,099		2,485
38.	3,805		1,332
39.	5,628		1,970
40.	7,957		2,785
41.	6,430		2,251
42.	7,661		2,681
43.	9,883		3,459
44.	12,801		4,480
45.	13,407		4,692
46.	10,462		3,662
47.	10,677		3,737
48.	13,523		4,733
49.	15,389		5,386
50.	11,159		3,906
51.	14,184		4,964
52.	14,213		4,975
53.	16,731		5,856
54.	15,936		5,578
55.	15,113		5,290
56.	13,421		4,697
57.	14,438		5,053
58.	14,411		5,044
59.	14,543		5,090
60.	15,481		5,418
61.	15,451		5,408
62.	16,151		5,653
63.	19,292		6,752
64.	18,168		6,359
65.	19,466		6,813
66.	17,135		5,997
67.	21,829		7,640
68.	21,107		7,387

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
69.	21,798		7,629
70.	23,347		8,171
71.	20,997		7,349
72.	20,323		7,113
73.	20,047		7,016
74.	22,172		7,760
75.	26,465		9,263
76.	21,733		7,607
77.	20,919		7,322
78.		21,885	5,471
79.	27,754		9,714
80.		16,564	4,141
81.	21,604		7,561
82.	18,114		6,340
83.	22,697		7,944
84.		19,792	4,948
85.		18,058	4,515
86.	17,022		5,958
87.	15,357		5,375
88.	32,266		11,293
89.	27,957		9,785
90.		18,064	4,516
91.	27,230		9,531
92.		2,789	697
93.		6,386	1,597
94.	37,973		13,291
95.	7,612		2,664
96.	33,935		11,877
97.	28,920		10,122
98.	15,203		5,321
99.	34,884		12,209
100.	19,559		6,846
101.	30,778		10,772
102.	34,625		12,119
103.	31,076		10,877
104.	5,424		1,898
105.	42,432		14,851
106.	35,805		12,532
107.	33,738		11,808
108.	25,164		8,807
109.	30,160		10,556
110.		26,318	6,580
111.	41,384		14,484
112.	9,836		3,443
113.		10,018	2,505
114.	39,306		13,757
115.		31,700	7,925
116.		31,801	7,950
117.	28,429		9,950
118.	34,530		12,086
119.	39,187		13,715
120.	47,650		16,678
121.	21,068		7,374
122.	34,647		12,126

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
123.	43,012		15,054
124.	35,811		12,534
125.	45,478		15,917
126.	45,667		15,983
127.	35,079		12,278
128.	33,389		11,686
129.	41,136		14,398
130.	34,044		11,915
131.		23,968	5,992
132.		27,938	6,985
133.		4,645	1,161
134.	36,560		12,796
135.	25,517		8,931
136.		32,062	8,016
137.	47,875		16,756
138.	40,935		14,327
139.		50,290	12,573
140.		46,675	11,669
141.		32,949	8,237
142.		42,654	10,664
143.		37,652	9,413
144.		49,821	12,455
145.		37,215	9,304
146.		64,103	16,026
147.		61,086	15,272
148.		52,694	13,174
149.		57,709	14,427
150.		38,879	9,720
151.		46,456	11,614
152.		52,188	13,047
153.		30,155	7,539
154.		46,249	11,562
155.		61,085	15,271
156.		60,782	15,196
157.		67,623	16,906
158.		54,301	13,575
159.		44,887	11,222
160.		49,326	12,332
161.		54,259	13,565
162.		58,881	14,720
163.		11,712	2,928
164.		61,265	15,316
165.		45,155	11,289
166.		57,856	14,464
167.		58,324	14,581
168.		44,939	11,235
169.		33,494	8,374
170.		58,754	14,689
171.		61,024	15,256
172.		49,697	12,424
173.		50,118	12,530
174.		52,457	13,114
175.		52,093	13,023
176.		53,522	13,381

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
177.		35,725	8,931
178.		34,165	8,541
179.		53,133	13,283
180.		35,390	8,848
181.		50,410	12,603
182.		37,545	9,386
183.		47,433	11,858
184.		48,482	12,121
185.		58,828	14,707
186.	27,780		9,723
187.		36,374	9,094
188.		37,293	9,323
189.		47,196	11,799
190.		20,630	5,158
191.		27,337	6,834
192.		60,524	15,131
193.	83,262		29,142
194.	78,360		27,426
195.		66,113	16,528
196.		51,649	12,912
197.		72,622	18,156
198.		65,446	16,362
199.		57,209	14,302
200.		57,119	14,280
201.		57,674	14,419
202.		72,086	18,022
203.		12,522	3,131
204.		50,393	12,598
205.		34,421	8,605
206.		64,897	16,224
207.		59,432	14,858
208.		72,380	18,095
209.		59,648	14,912
210.	99,333		34,767
211.		45,369	11,342
212.	86,000		30,100
213.	83,890		29,362
214.	97,478		34,117
215.	87,827		30,739
216.	90,167		31,558
217.	70,826		24,789
218.		63,472	15,868
219.	71,782		25,124
220.		60,942	15,236
221.	69,376		24,282
222.	56,324		19,713
223.	57,652		20,178
224.	71,196		24,919
225.	57,244		20,035
226.		59,893	14,973
227.	99,082		34,679
228.	76,638		26,823
229.		86,210	21,553
230.		67,209	16,802

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
231.		64,743	16,186
232.		48,113	12,028
233.		97,970	24,493
234.		55,671	13,918
235.		55,403	13,851
236.	105,145		36,801
237.		73,839	18,460
238.		84,610	21,153
239.		57,013	14,253
240.		47,136	11,784
241.		75,657	18,914
242.	93,763		32,817
243.	97,877		34,257
244.	111,937		39,178
245.		53,769	13,442
246.	80,719		28,252
247.		111,787	27,947
248.	101,623		35,568
249.	96,102		33,636
250.		66,123	16,531
251.		73,333	18,333
252.		82,834	20,709
253.		96,787	24,197
254.		59,029	14,757
255.		65,157	16,289
256.	76,703		26,846
257.		49,617	12,404
258.		97,194	24,299
259.		68,370	17,093
260.	93,226		32,629
261.	112,895		39,513
262.	96,452		33,758
263.	90,138		31,548
264.	100,180		35,063
265.	86,287		30,200
266.	88,385		30,935
267.	75,327		26,364
268.	96,736		33,858
269.	85,044		29,765
270.	80,099		28,035
271.	76,391		26,737
272.	93,540		32,739
273.	79,709		27,898
274.	107,814		37,735
275.	103,195		36,118
276.	107,272		37,545
277.	99,751		34,913
278.	77,163		27,007
279.	105,580		36,953
280.	91,678		32,087
281.	92,153		32,254
282.	112,501		39,375
283.	102,689		35,941
284.	94,754		33,164

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
285.	69,704		24,396
286.	107,961		37,786
287.		65,851	16,463
288.		81,259	20,315
289.		67,751	16,938
290.		14,791	3,698
291.		51,338	12,835
292.		83,947	20,987
293.		58,880	14,720
294.		103,312	25,828
295.		95,925	23,981
296.		71,522	17,881
297.		81,008	20,252
298.		86,260	21,565
299.		74,068	18,517
300.		75,665	18,916
301.		82,963	20,741
302.		85,259	21,315
303.		92,209	23,052
304.		80,148	20,037
305.		93,940	23,485
306.		52,932	13,233
307.		98,583	24,646
308.		81,172	20,293
309.		79,153	19,788
310.		75,985	18,996
311.		118,409	29,602
312.		85,809	21,452
313.		84,077	21,019
314.		91,818	22,955
315.		104,570	26,143
316.		100,106	25,027
317.		88,080	22,020
318.		97,943	24,486
319.		69,876	17,469
320.		89,749	22,437
321.		80,269	20,067
322.		74,245	18,561
323.		67,754	16,939
324.		77,138	19,285
325.		64,431	16,108
326.		46,261	11,565
327.		83,739	20,935
328.		58,322	14,581
329.		67,491	16,873
330.		67,165	16,791
331.		55,830	13,958
332.		90,306	22,577
333.		79,280	19,820
334.		75,655	18,914
335.		80,104	20,026
336.		94,364	23,591
337.		97,852	24,463
338.		116,068	29,017

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
339.		86,751	21,688
340.		83,941	20,985
341.		104,824	26,206
342.		95,433	23,858
343.		92,949	23,237
344.		83,726	20,932
345.		87,876	21,969
346.		52,636	13,159
347.		103,288	25,822
348.		80,810	20,203
349.		80,097	20,024
350.		84,381	21,095
351.		92,059	23,015
352.		88,588	22,147
353.		87,208	21,802
354.		70,915	17,729
355.		89,553	22,388
356.		94,338	23,585
357.		74,943	18,736
358.		69,300	17,325
359.		109,865	27,466
360.		49,451	12,363
361.		76,652	19,163
362.		62,371	15,593
363.		60,085	15,021
364.		81,541	20,385
365.		65,945	16,486
366.		62,880	15,720
367.		66,479	16,620
368.		72,650	18,163
369.		100,810	25,203
370.		80,979	20,245
371.		57,213	14,303
372.		50,081	12,520
373.		68,559	17,140
374.		89,523	22,381
375.		70,026	17,507
376.		75,209	18,802
377.		57,237	14,309
378.		98,075	24,519
379.		85,129	21,282
380.		111,287	27,822
381.		90,009	22,502
382.		92,060	23,015
383.		63,547	15,887
384.		84,131	21,033
385.		83,350	20,838
386.		82,988	20,747
387.		100,320	25,080
388.		80,672	20,168
389.		56,858	14,215
390.		55,382	13,846
391.		84,087	21,022
392.		136,298	34,075

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
393.		61,741	15,435
394.		59,086	14,772
395.		79,171	19,793
396.		65,057	16,264
397.		83,449	20,862
398.		74,067	18,517
399.		100,254	25,064
400.		80,974	20,244
401.		89,150	22,288
402.		46,750	11,688
403.		65,655	16,414
404.		77,021	19,255
405.		71,960	17,990
406.		78,800	19,700
407.		78,432	19,608
408.		78,635	19,659
409.		80,778	20,195
410.		81,363	20,341
411.		75,587	18,897
412.		70,549	17,637
413.		93,265	23,316
414.		83,293	20,823
415.		74,454	18,614
416.		71,667	17,917
417.		62,019	15,505
418.		63,142	15,786
419.		81,392	20,348
420.		76,426	19,107
421.		67,537	16,884
422.		70,854	17,714
423.		74,216	18,554
424.		60,261	15,065
425.		74,235	18,559
426.		76,449	19,112
427.		70,318	17,580
428.		58,713	14,678
429.		50,016	12,504
430.		48,549	12,137
431.		53,654	13,414
432.		69,900	17,475
433.		72,735	18,184
434.		69,003	17,251
435.		79,273	19,818
436.		63,399	15,850
437.		67,932	16,983
438.		62,343	15,586
439.		78,452	19,613
440.		62,721	15,680
441.		72,963	18,241
442.		81,720	20,430
443.		72,609	18,152
444.		80,855	20,214
445.		66,125	16,531
446.		71,687	17,922

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
447.		70,285	17,571
448.		68,745	17,186
449.		42,465	10,616
450.		72,286	18,072
451.		63,396	15,849
452.		56,181	14,045
453.		71,889	17,972
454.		73,864	18,466
455.		75,416	18,854
456.		70,953	17,738
457.		65,469	16,367
458.		62,200	15,550
459.		52,912	13,228
460.		73,395	18,349
461.		55,618	13,905
462.		62,595	15,649
463.		74,298	18,575
464.		60,154	15,039
465.		42,067	10,517
466.		53,344	13,336
467.		55,670	13,918
468.		48,375	12,094
469.		42,534	10,634
470.		39,425	9,856
471.		69,402	17,351
472.		91,565	22,891
473.		65,604	16,401
474.		72,637	18,159
475.		68,288	17,072
476.		58,175	14,544
477.		68,027	17,007
478.		63,661	15,915
479.		67,312	16,828
480.		63,083	15,771
481.		52,986	13,247
482.		72,138	18,035
483.		66,249	16,562
484.		78,182	19,546
485.		74,615	18,654
486.		56,985	14,246
487.		92,962	23,241
488.		69,962	17,491
489.		66,569	16,642
490.		53,722	13,431
491.		61,986	15,497
492.		66,986	16,747
493.		79,991	19,998
494.		89,267	22,317
495.		61,407	15,352
496.		72,882	18,221
497.		65,917	16,479
498.		66,812	16,703
499.		66,669	16,667
500.		69,893	17,473

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
501.		58,428	14,607
502.		80,073	20,018
503.		71,229	17,807
504.		66,013	16,503
505.		52,827	13,207
506.		77,398	19,350
507.		58,049	14,512
508.		53,506	13,377
509.		63,634	15,909
510.		64,136	16,034
511.		82,707	20,677
512.		57,935	14,484
513.		61,874	15,469
514.		57,384	14,346
515.		76,359	19,090
516.		60,643	15,161
517.		66,475	16,619
518.		69,510	17,378
519.		50,809	12,702
520.		75,750	18,938
521.		68,629	17,157
522.		63,549	15,887
523.		64,898	16,225
524.		67,758	16,940
525.		58,131	14,533
526.		62,550	15,638
527.		67,461	16,865
528.		66,762	16,691
529.		66,987	16,747
530.		61,432	15,358
531.		64,842	16,211
532.		60,731	15,183
533.		62,953	15,738
534.		53,843	13,461
535.		49,548	12,387
536.		65,449	16,362
537.		42,714	10,679
538.		45,601	11,400
539.		55,913	13,978
540.		54,517	13,629
541.		44,032	11,008
542.		69,639	17,410
543.		50,013	12,503
544.		86,135	21,534
545.		63,666	15,917
546.		42,894	10,724
547.		55,604	13,901
548.		49,098	12,275
549.		50,053	12,513
550.		36,019	9,005
551.		45,023	11,256
552.		38,270	9,568
553.		46,560	11,640
554.		59,019	14,755

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
555.		29,484	7,371
556.		60,579	15,145
557.		57,926	14,482
558.		54,231	13,558
559.		38,917	9,729
560.		35,223	8,806
561.		58,161	14,540
562.		40,916	10,229
563.		62,083	15,521
564.		75,704	18,926
565.		33,621	8,405
566.		45,802	11,451

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.

For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
1.	425		425
2.	2,301		2,301
3.	2,110		2,110
4.	1,507		1,507
5.	1,507		1,507
6.	3,397		3,397
7.	2,082		2,082
8.	2,548		2,548
9.	4,685		4,685
10.	959		959
11.	1,890		1,890
12.	2,082		2,082
13.	4,685		4,685
14.	1,890		1,890
15.	4,219		4,219
16.	5,973		5,973
17.	4,329		4,329
18.	4,233		4,233
19.	4,233		4,233
20.	4,479		4,479
21.	2,685		2,685
22.	4,630		4,630
23.	9,534		9,534
24.	1,890		1,890
25.	4,315		4,315
26.	9,534		9,534
27.	219		219

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
28.	247		247
29.	247		247
30.	274		274
31.	329		329
32.	411		411
33.	466		466
34.	575		575
35.	658		658
36.	712		712
37.	712		712
38.	712		712
39.	712		712
40.	712		712
41.	712		712
42.	767		767
43.	959		959
44.	959		959
45.	986		986
46.	1,014		1,014
47.	1,014		1,014
48.	1,178		1,178
49.	1,205		1,205
50.	1,205		1,205
51.	1,205		1,205
52.	1,479		1,479
53.	1,479		1,479
54.	1,479		1,479
55.	1,479		1,479
56.	1,479		1,479
57.	1,479		1,479
58.	1,479		1,479
59.	1,479		1,479
60.	1,479		1,479
61.	1,479		1,479
62.	1,479		1,479
63.	1,562		1,562
64.	1,616		1,616
65.	1,753		1,753
66.	1,781		1,781
67.	1,945		1,945
68.	2,000		2,000
69.	2,055		2,055
70.	2,055		2,055
71.	2,055		2,055
72.	2,055		2,055
73.	2,055		2,055
74.	2,055		2,055
75.	2,110		2,110
76.	2,192		2,192
77.	2,192		2,192
78.	1,151		1,151
79.	2,356		2,356
80.	1,260		1,260

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
81.	2,548		2,548
82.	2,548		2,548
83.	2,575		2,575
84.	1,288		1,288
85.	1,342		1,342
86.	2,685		2,685
87.	2,685		2,685
88.	2,685		2,685
89.	2,740		2,740
90.	1,370		1,370
91.	2,877		2,877
92.	697		697
93.	1,507		1,507
94.	3,068		3,068
95.	2,664		2,664
96.	3,205		3,205
97.	3,205		3,205
98.	3,205		3,205
99.	3,205		3,205
100.	3,205		3,205
101.	3,205		3,205
102.	3,205		3,205
103.	3,205		3,205
104.	1,898		1,898
105.	3,260		3,260
106.	3,260		3,260
107.	3,260		3,260
108.	3,315		3,315
109.	3,315		3,315
110.	1,658		1,658
111.	3,452		3,452
112.	3,443		3,443
113.	1,781		1,781
114.	3,644		3,644
115.	1,836		1,836
116.	1,849		1,849
117.	3,973		3,973
118.	3,973		3,973
119.	3,973		3,973
120.	3,973		3,973
121.	3,973		3,973
122.	3,973		3,973
123.	3,973		3,973
124.	3,973		3,973
125.	3,973		3,973
126.	3,973		3,973
127.	3,973		3,973
128.	3,973		3,973
129.	3,973		3,973
130.	3,973		3,973
131.	1,986		1,986
132.	1,986		1,986
133.	1,161		1,161

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
134.	4,384		4,384
135.	4,411		4,411
136.	2,384		2,384
137.	4,795		4,795
138.	4,795		4,795
139.	2,411		2,411
140.	2,493		2,493
141.	2,507		2,507
142.	2,630		2,630
143.	2,644		2,644
144.	2,644		2,644
145.	2,644		2,644
146.	2,644		2,644
147.	2,644		2,644
148.	2,644		2,644
149.	2,644		2,644
150.	2,644		2,644
151.	2,644		2,644
152.	2,644		2,644
153.	2,644		2,644
154.	2,644		2,644
155.	2,644		2,644
156.	2,644		2,644
157.	2,644		2,644
158.	2,644		2,644
159.	2,644		2,644
160.	2,644		2,644
161.	2,644		2,644
162.	2,644		2,644
163.	2,644		2,644
164.	2,644		2,644
165.	2,644		2,644
166.	2,644		2,644
167.	2,644		2,644
168.	2,644		2,644
169.	2,644		2,644
170.	2,644		2,644
171.	2,644		2,644
172.	2,644		2,644
173.	2,644		2,644
174.	2,644		2,644
175.	2,644		2,644
176.	2,644		2,644
177.	2,644		2,644
178.	2,644		2,644
179.	2,644		2,644
180.	2,644		2,644
181.	2,644		2,644
182.	2,644		2,644
183.	2,644		2,644
184.	2,849		2,849
185.	2,877		2,877
186.	5,836		5,836

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
187.	3,082		3,082
188.	3,164		3,164
189.	3,425		3,425
190.	3,479		3,479
191.	3,658		3,658
192.	3,740		3,740
193.	7,726		7,726
194.	7,781		7,781
195.	3,904		3,904
196.	3,904		3,904
197.	3,904		3,904
198.	3,904		3,904
199.	3,904		3,904
200.	3,904		3,904
201.	3,904		3,904
202.	3,904		3,904
203.	3,131		3,131
204.	3,904		3,904
205.	3,904		3,904
206.	3,904		3,904
207.	3,904		3,904
208.	3,904		3,904
209.	3,904		3,904
210.	7,890		7,890
211.	3,945		3,945
212.	7,945		7,945
213.	8,137		8,137
214.	8,247		8,247
215.	8,301		8,301
216.	8,438		8,438
217.	8,658		8,658
218.	4,548		4,548
219.	9,288		9,288
220.	4,712		4,712
221.	9,534		9,534
222.	9,534		9,534
223.	9,534		9,534
224.	9,534		9,534
225.	9,534		9,534
226.	4,849		4,849
227.	9,836		9,836
228.	9,973		9,973
229.	5,000		5,000
230.	5,000		5,000
231.	5,000		5,000
232.	5,000		5,000
233.	5,000		5,000
234.	5,000		5,000
235.	5,000		5,000
236.	10,000		10,000
237.	5,000		5,000
238.	5,000		5,000
239.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
240.	5,000		5,000
241.	5,000		5,000
242.	10,000		10,000
243.	10,000		10,000
244.	10,000		10,000
245.	5,000		5,000
246.	10,000		10,000
247.	5,000		5,000
248.	10,000		10,000
249.	10,000		10,000
250.	5,000		5,000
251.	5,000		5,000
252.	5,000		5,000
253.	5,000		5,000
254.	5,000		5,000
255.	5,000		5,000
256.	10,000		10,000
257.	5,000		5,000
258.	5,000		5,000
259.	5,000		5,000
260.	10,000		10,000
261.	10,000		10,000
262.	10,000		10,000
263.	10,000		10,000
264.	10,000		10,000
265.	10,000		10,000
266.	10,000		10,000
267.	10,000		10,000
268.	10,000		10,000
269.	10,000		10,000
270.	10,000		10,000
271.	10,000		10,000
272.	10,000		10,000
273.	10,000		10,000
274.	10,000		10,000
275.	10,000		10,000
276.	10,000		10,000
277.	10,000		10,000
278.	10,000		10,000
279.	10,000		10,000
280.	10,000		10,000
281.	10,000		10,000
282.	10,000		10,000
283.	10,000		10,000
284.	10,000		10,000
285.	10,000		10,000
286.	10,000		10,000
287.	5,000		5,000
288.	5,000		5,000
289.	5,000		5,000
290.	3,698		3,698
291.	5,000		5,000
292.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
293.	5,000		5,000
294.	5,000		5,000
295.	5,000		5,000
296.	5,000		5,000
297.	5,000		5,000
298.	5,000		5,000
299.	5,000		5,000
300.	5,000		5,000
301.	5,000		5,000
302.	5,000		5,000
303.	5,000		5,000
304.	5,000		5,000
305.	5,000		5,000
306.	5,000		5,000
307.	5,000		5,000
308.	5,000		5,000
309.	5,000		5,000
310.	5,000		5,000
311.	5,000		5,000
312.	5,000		5,000
313.	5,000		5,000
314.	5,000		5,000
315.	5,000		5,000
316.	5,000		5,000
317.	5,000		5,000
318.	5,000		5,000
319.	5,000		5,000
320.	5,000		5,000
321.	5,000		5,000
322.	5,000		5,000
323.	5,000		5,000
324.	5,000		5,000
325.	5,000		5,000
326.	5,000		5,000
327.	5,000		5,000
328.	5,000		5,000
329.	5,000		5,000
330.	5,000		5,000
331.	5,000		5,000
332.	5,000		5,000
333.	5,000		5,000
334.	5,000		5,000
335.	5,000		5,000
336.	5,000		5,000
337.	5,000		5,000
338.	5,000		5,000
339.	5,000		5,000
340.	5,000		5,000
341.	5,000		5,000
342.	5,000		5,000
343.	5,000		5,000
344.	5,000		5,000
345.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
346.	5,000		5,000
347.	5,000		5,000
348.	5,000		5,000
349.	5,000		5,000
350.	5,000		5,000
351.	5,000		5,000
352.	5,000		5,000
353.	5,000		5,000
354.	5,000		5,000
355.	5,000		5,000
356.	5,000		5,000
357.	5,000		5,000
358.	5,000		5,000
359.	5,000		5,000
360.	5,000		5,000
361.	5,000		5,000
362.	5,000		5,000
363.	5,000		5,000
364.	5,000		5,000
365.	5,000		5,000
366.	5,000		5,000
367.	5,000		5,000
368.	5,000		5,000
369.	5,000		5,000
370.	5,000		5,000
371.	5,000		5,000
372.	5,000		5,000
373.	5,000		5,000
374.	5,000		5,000
375.	5,000		5,000
376.	5,000		5,000
377.	5,000		5,000
378.	5,000		5,000
379.	5,000		5,000
380.	5,000		5,000
381.	5,000		5,000
382.	5,000		5,000
383.	5,000		5,000
384.	5,000		5,000
385.	5,000		5,000
386.	5,000		5,000
387.	5,000		5,000
388.	5,000		5,000
389.	5,000		5,000
390.	5,000		5,000
391.	5,000		5,000
392.	5,000		5,000
393.	5,000		5,000
394.	5,000		5,000
395.	5,000		5,000
396.	5,000		5,000
397.	5,000		5,000
398.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
399.	5,000		5,000
400.	5,000		5,000
401.	5,000		5,000
402.	5,000		5,000
403.	5,000		5,000
404.	5,000		5,000
405.	5,000		5,000
406.	5,000		5,000
407.	5,000		5,000
408.	5,000		5,000
409.	5,000		5,000
410.	5,000		5,000
411.	5,000		5,000
412.	5,000		5,000
413.	5,000		5,000
414.	5,000		5,000
415.	5,000		5,000
416.	5,000		5,000
417.	5,000		5,000
418.	5,000		5,000
419.	5,000		5,000
420.	5,000		5,000
421.	5,000		5,000
422.	5,000		5,000
423.	5,000		5,000
424.	5,000		5,000
425.	5,000		5,000
426.	5,000		5,000
427.	5,000		5,000
428.	5,000		5,000
429.	5,000		5,000
430.	5,000		5,000
431.	5,000		5,000
432.	5,000		5,000
433.	5,000		5,000
434.	5,000		5,000
435.	5,000		5,000
436.	5,000		5,000
437.	5,000		5,000
438.	5,000		5,000
439.	5,000		5,000
440.	5,000		5,000
441.	5,000		5,000
442.	5,000		5,000
443.	5,000		5,000
444.	5,000		5,000
445.	5,000		5,000
446.	5,000		5,000
447.	5,000		5,000
448.	5,000		5,000
449.	5,000		5,000
450.	5,000		5,000
451.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
452.	5,000		5,000
453.	5,000		5,000
454.	5,000		5,000
455.	5,000		5,000
456.	5,000		5,000
457.	5,000		5,000
458.	5,000		5,000
459.	5,000		5,000
460.	5,000		5,000
461.	5,000		5,000
462.	5,000		5,000
463.	5,000		5,000
464.	5,000		5,000
465.	5,000		5,000
466.	5,000		5,000
467.	5,000		5,000
468.	5,000		5,000
469.	5,000		5,000
470.	5,000		5,000
471.	5,000		5,000
472.	5,000		5,000
473.	5,000		5,000
474.	5,000		5,000
475.	5,000		5,000
476.	5,000		5,000
477.	5,000		5,000
478.	5,000		5,000
479.	5,000		5,000
480.	5,000		5,000
481.	5,000		5,000
482.	5,000		5,000
483.	5,000		5,000
484.	5,000		5,000
485.	5,000		5,000
486.	5,000		5,000
487.	5,000		5,000
488.	5,000		5,000
489.	5,000		5,000
490.	5,000		5,000
491.	5,000		5,000
492.	5,000		5,000
493.	5,000		5,000
494.	5,000		5,000
495.	5,000		5,000
496.	5,000		5,000
497.	5,000		5,000
498.	5,000		5,000
499.	5,000		5,000
500.	5,000		5,000
501.	5,000		5,000
502.	5,000		5,000
503.	5,000		5,000
504.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
505.	5,000		5,000
506.	5,000		5,000
507.	5,000		5,000
508.	5,000		5,000
509.	5,000		5,000
510.	5,000		5,000
511.	5,000		5,000
512.	5,000		5,000
513.	5,000		5,000
514.	5,000		5,000
515.	5,000		5,000
516.	5,000		5,000
517.	5,000		5,000
518.	5,000		5,000
519.	5,000		5,000
520.	5,000		5,000
521.	5,000		5,000
522.	5,000		5,000
523.	5,000		5,000
524.	5,000		5,000
525.	5,000		5,000
526.	5,000		5,000
527.	5,000		5,000
528.	5,000		5,000
529.	5,000		5,000
530.	5,000		5,000
531.	5,000		5,000
532.	5,000		5,000
533.	5,000		5,000
534.	5,000		5,000
535.	5,000		5,000
536.	5,000		5,000
537.	5,000		5,000
538.	5,000		5,000
539.	5,000		5,000
540.	5,000		5,000
541.	5,000		5,000
542.	5,000		5,000
543.	5,000		5,000
544.	5,000		5,000
545.	5,000		5,000
546.	5,000		5,000
547.	5,000		5,000
548.	5,000		5,000
549.	5,000		5,000
550.	5,000		5,000
551.	5,000		5,000
552.	5,000		5,000
553.	5,000		5,000
554.	5,000		5,000
555.	5,000		5,000
556.	5,000		5,000
557.	5,000		5,000

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
558.	5,000		5,000
559.	5,000		5,000
560.	5,000		5,000
561.	5,000		5,000
562.	5,000		5,000
563.	5,000		5,000
564.	5,000		5,000
565.	5,000		5,000
566.	5,000		5,000

Ontario apprenticeship training tax credit (total of amounts in column N) 500 2,577,227 **O**

Or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = ... ______ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . HYDRO ONE NETWORKS INC.

Taxation Year . . . . 2018-01-01 to 2018-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 32

Type of corporation . . . . Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial* . . . . -1,872,459

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		28,604,965
Taxable income		26,657,334
Donations		732,573
Calculation of income from an active business carried on in Canada		28,604,965
Dividends paid		500,000
Dividends paid – Regular		
Dividends paid – Eligible	500,000	
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		10,129,787

Credits against part I tax		**Summary of tax**		**Refunds/credits**	
Small business deduction		Part I	968	ITC refund	
M&P deduction		Part IV		Dividends refund:	
Foreign tax credit		Part III.1		– Eligible dividends	
Investment tax credits	3,997,633	Other*		– Non-eligible dividends	
Abatement/Other*	6,131,186	Provincial or territorial tax	19,042,743	Instalments	20,916,170
				Other*	
				Balance due/refund (–)	-1,872,459

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Non-capital losses	891,343,131
Capital losses/L.P.P.	139,587
Current year's balance of SR&ED expenditures (T661)	11,364,231
Financial statement reserve	1,770,546,656
Other reserves	40,305,704

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	28,604,965		
Taxable income	26,657,334		
% Allocation	100.00		
Attributed taxable income	26,657,334		
Tax payable before deduction*	3,065,593		
Deductions and credits	434,123		
Net tax payable	2,631,470		
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	22,571,457		
Instalments and refundable credits	3,528,714		
Balance due/Refund (-)	19,042,743		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510 64,803,147

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
			21,743,581,038	21,743,581,038
1228185 Ontario Inc.				
1937672 Ontario Inc.				
1937680 Ontario Inc.				
1937681 Ontario Inc.				
1938454 Ontario Inc.				
1943404 Ontario Inc.				
2486267 Ontario Inc.				
2486268 Ontario Inc.				
2587264 Ontario Inc.				
2587265 Ontario Inc.				
Haldimand County Energy Inc.				
Haldimand County Hydro Inc.				
Hydro One B2M Holdings Inc.				
Hydro One B2M LP Inc.				
Hydro One East-West Tie Inc.				
Hydro One Holdings Limited				
Hydro One Inc.				
Hydro One Indigenous Partnerships GP Inc.				
Hydro One Lake Erie Link Management Inc.				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Hydro One Limited				
Hydro One Remote Communites Inc.				
Hydro One Sault Ste. Marie Holding Corp.				
Hydro One Sault Ste. Marie Holdings Inc.				
Hydro One Sault Ste. Marie Inc.				
Hydro One Telecom Inc.				
Hydro One Telecom Link Limited				
Municipal Billing Services Inc.				
Norfolk Energy Inc.				
Norfolk Power Distribution Inc.				
Olympus Corp.				
Olympus Holding Corp.				
Woodstock Hydro Services Inc.				
Total			21,743,581,038	21,743,581,038

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the $1 million deduction (CO-1137.A and CO-1137.E)	Paid-up capital used to determine the applicability of Form CO-737.SI
Total				

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
	21,366,539,700
1228185 Ontario Inc.	
1937672 Ontario Inc.	
1937680 Ontario Inc.	
1937681 Ontario Inc.	
1938454 Ontario Inc.	
1943404 Ontario Inc.	
2486267 Ontario Inc.	
2486268 Ontario Inc.	
2587264 Ontario Inc.	
2587265 Ontario Inc.	
Haldimand County Energy Inc.	
Haldimand County Hydro Inc.	
Hydro One B2M Holdings Inc.	
Hydro One B2M LP Inc.	
Hydro One East-West Tie Inc.	

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Hydro One Holdings Limited	
Hydro One Inc.	
Hydro One Indigenous Partnerships GP Inc.	
Hydro One Lake Erie Link Management Inc.	
Hydro One Limited	
Hydro One Remote Communites Inc.	
Hydro One Sault Ste. Marie Holding Corp.	
Hydro One Sault Ste. Marie Holdings Inc.	
Hydro One Sault Ste. Marie Inc.	
Hydro One Telecom Inc.	
Hydro One Telecom Link Limited	
Municipal Billing Services Inc.	
Norfolk Energy Inc.	
Norfolk Power Distribution Inc.	
Olympus Corp.	
Olympus Holding Corp.	
Woodstock Hydro Services Inc.	
Total	21,366,539,700

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

OEB INTERROGATORY #211

Reference:
F-07-04 Table 2

Interrogatory:
At the above reference, Hydro One provides a summary of its historical and forecast property taxes.

a) There was a property tax adjustment of $12.1 million in 2017. Please explain why this adjustment appears to only be one-time in nature and has no impact on lowering property taxes for the future periods presented in the table?

Response:
a) Property taxes were lower than budget by $12.1 million due primarily to a reduction in the provision for payments in lieu of property taxes following a favourable reassessment of the regulations and estimates related to the liabilities.

OEB INTERROGATORY #212

Reference:
F-06-01

Interrogatory:
At the above reference, Hydro One discusses the depreciation it is seeking to recover over the term of its application and the related study that was undertaken to underpin the depreciation rates used.

a) If the depreciation rates used remained consistent with the ones approved by the OEB in Hydro One's 2017-2018 transmission rates application, please recalculate what the depreciation expense would be annually over the term of the current application.

b) In Hydro One's recent distribution rates application, the study that was undertaken to underpin the related depreciation rates was not used and the rates remained unchanged from what had been approved in the previous proceeding. Please explain why that was appropriate in the distribution rates proceeding but is not appropriate for the transmission rates proceeding?

Response:
a) Please see the table below for the depreciation expense on fixed assets for 2020-2022 if the current depreciation rates were applied.

	Depreciation Expense on fixed assets ($M)
2020	425.3
2021	446.1
2022	468.8

Please also refer to Exhibit I, Tab 04, Schedule LPMA-11 where the impact relative to maintaining the current depreciation rates is shown.

b) In EB-2017-0049 Hydro One elected to maintain its existing depreciation rates for its Distribution application instead of adopting the rates proposed in the 2016 Foster Associates study to avoid a fluctuation in depreciation rates. The 2016 Foster Associates study would have created, if implemented, increased depreciation rates and expense over the 2018 to 2022 rate setting period. The increase would have resulted in a rate impact of approximately 2%.

In the current application for Transmission rates for the period 2020-2022, a new study was performed, referred to as the 2017 Foster Associates study which proposes new depreciation rates. Hydro One seeks to adopt the proposed rates based on the objectives of depreciation accounting, i.e., cost allocation over economic life in proportion to the consumption of service potential. Please refer to Exhibit F, Tab 6, Schedule 1 Attachment 1 for further discussion on the principles of the 2017 Depreciation Review.

OEB INTERROGATORY #213

Reference:
H-01-01

Interrogatory:
At the above reference, Hydro One has provided an excel version of its DVA continuity schedule.

a) Please prepare a DVA continuity schedule using the OEB approved DVA continuity schedule model for 2020 rate filers. This updated model is due to be released by the OEB in July 2019 and can be found on the OEB website.

Response:
a) The OEB approved DVA continuity schedule model is populated with Distribution specific accounts and balances reported as part of the RRR submission which does not apply to this Transmission application. Additionally, the OEB approved DVA continuity schedule model includes calculations to derive rate riders for distribution rate classes. These calculations are not relevant for electricity transmitters as DVA balances are disposed of as adjustments to a transmitter's approved revenue requirement rather than through separate class-specific rate riders, as is the case in distribution rate proceedings. Hydro One filed an Excel continuity schedule in Exhibit H, Tab 01, Schedule 05, Attachment 01 which is consistent with prior applications and the DVA continuity schedule.

Witness: Samir Chhelavda

OEB INTERROGATORY #214

Reference:
H-01-03 Table 1

Interrogatory:
At the above reference, Hydro One has provided a table that summarizes the request to dispose of $20.5 million with respect to its December 31, 2018 audited DVA account balances. Hydro One has requested disposition over a three-year period.

a) Given the relatively small balance being disposed of in this proceeding, please explain why Hydro One is seeking disposition over a three-year period as opposed the default one-year period that the OEB generally prescribes.

Response:
a) In an effort to mitigate the rate impacts on customers, Hydro One is proposing a disposition period of three years.

OEB INTERROGATORY #215

Reference:
H-01-01 p.4

Interrogatory:
At the above reference, Hydro One describes the balance within its Excess Export Service Revenue account.

a) Please confirm that the $4.8 million balance within this account represents only the difference between forecast export service revenue approved for 2018 compared to actual 2018 (plus applicable interest)

b) Please provide the actual export service revenue for 2018.

c) Can the above actual number for 2018 be tied to Hydro One's 2018 audited financial statements? If so, please provide the reference. If not, please explain how this actual balance is derived and tracked by Hydro One.

Response:
a) The $4.8 million balance represents the forecasted excess export service revenue variance account balance as of December 31, 2019. The amount is comprised of the audited December 31, 2018 balance (which includes the difference between forecast export service revenue approved for 2018 compared to actual 2018, plus applicable interest), Board approved dispositions during 2019, and forecasted interest. Please refer to Exhibit H, Tab 01, Schedule 05, Attachment 01 for the continuity schedule.

b) The actual export service revenue for 2018 was $35,381,429.

c) No. The figure in part b) is included in total revenues in the 2018 Audited Hydro One Networks Transmission financial statements. The number is the difference between forecasted excess export service revenue embedded in rates and the actual revenues as per the monthly IESO invoice. Since the IESO invoice is received a month in arrears, an estimate based on prior years is used as an accrual in the month and the applicable adjusting entry is recorded in the following month. On a net basis, the yearly difference between actual and accrual is not material as the accrual is only present in December.

OEB INTERROGATORY #216

Reference:
H-01-01 p.4-5

Interrogatory:
At the above reference, Hydro One describes the balance within its External Secondary Land Use Revenue account.

a) Please confirm that the $10.4 million balance within this account represents only the difference between forecast external secondary land use revenues approved by the OEB for 2018 compared to actual 2018 (plus applicable interest)

b) Please provide the actual external secondary land use revenues for 2018.

c) Can the above actual number for 2018 be tied to Hydro One's 2018 audited financial statements? If so, please provide the reference. If not, please explain how this actual balance is derived and tracked by Hydro One.

Response:
a) The ($10.4) million represents the forecasted external secondary land use revenue variance account balance as of December 31, 2019. The balance is comprised of the audited December 31, 2018 amount (which includes the difference between forecast external secondary land use revenues approved for 2018 compared to actual 2018, plus applicable interest), Board approved dispositions during 2019, and forecasted interest. Please refer to Exhibit H, Tab 01, Schedule 05, Attachment 01 for the continuity schedule.

b) The actual external secondary land use revenues for 2018 was $25,582,249 million.

c) No. The figure in part b) is included in total revenues in the 2018 Audited Hydro One Networks Transmission financial statements. External revenues are recorded as revenue is earned from the related projects.

Witness: Samir Chhelavda

OEB INTERROGATORY #217

Reference:
H-01-01 p.5-6

Interrogatory:
At the above reference, Hydro One describes the balance within its External Station Maintenance, E&CS and Other External Revenue account.

a) Please confirm that the $4.5 million balance within this account represents only the difference between the OEB approved and actual external station maintenance, E&CS and other external revenues for 2018. (plus applicable interest)

b) Please provide the actual maintenance, E&CS and other revenues for 2018.

c) Can the above actual number for 2018 be tied to Hydro One's 2018 audited financial statements? If so, please provide the reference. If not, please explain how this actual balance is derived and tracked by Hydro One.

Response:
a) The $4.5 million represents the forecasted net external station maintenance, E&CS, and other revenue variance account balance as of December 31, 2019. The balance is comprised of the audited December 31, 2018 amount (which includes the difference between net forecast external station maintenance, E&CS, and other revenues approved for 2018 compared to actual 2018, plus applicable interest), Board approved dispositions during 2019, and forecasted interest. Please refer to Exhibit H, Tab 01, Schedule 05, Attachment 01 for the continuity schedule.

b) The actual net (revenues less cost of sales) external station maintenance, E&CS, and other revenue for 2018 was ($3,501,719) million.

c) No. The figure in part b) is included in total revenues and OM&A in the 2018 Audited Hydro One Networks Transmission financial statements. External revenues are recorded as revenue is earned from related projects. The corresponding cost of sales is recorded as they are incurred.

Witness: Samir Chhelavda

OEB INTERROGATORY #218

Reference:
H-01-01 p.6

Interrogatory:
At the above reference, Hydro One describes its Tax Rate Change account and has indicated that the balance is currently zero.

The Government of Canada's 2018 Fall Economic Statement proposed a number of tax changes related to CCA for certain eligible property acquired after November 20, 2018, which it further confirmed in its 2019 Budget.

a) Shouldn't amounts related to this tax change have been captured within this account for 2018? If so, then why is the account balance zero? If not, please explain why Hydro One believes that the impact of the aforementioned tax change should not be captured here.

Response:
a) As discussed in Exhibit I, Tab 01, Schedule OEB-208 part (c), accelerated CCA was enacted on June 21, 2019 and was not claimed in the 2018 tax return as the majority of the in-service additions would not qualify for accelerated CCA. Furthermore, the Tax Rate Change account is based on balances at the end of December 31, 2018, which would be zero as the accelerated CCA legislation was enacted subsequently.

OEB INTERROGATORY #219

Reference:

H-01-01 p.7-8

Interrogatory:

At the above reference, Hydro One describes the balance within its Pension Costs Differential Account.

a) Please confirm that the $4.5 million balance within this account represents only the difference between forecast approved and actual OM&A portion of pension contributions for 2018 (plus applicable interest)

b) Please provide both the pension contributions approved by the OEB for 2018 and the actual 2018 OM&A portion of pension contributions made by Hydro One.

c) Can the above actual number for 2018 be tied to Hydro One's 2018 audited financial statements? If so, please provide the reference. If not, please explain how this actual balance is derived and tracked by Hydro One.

Response:

a) The ($4.5) million represents the forecasted pension costs differential account balance at December 31, 2019. The balance is comprised of the audited December 31, 2018 balance (which includes the difference between forecast pension OM&A costs approved compared to actual 2018, plus applicable interest), Board approved dispositions during 2019, and forecasted interest. Please refer to Exhibit H, Tab 01, Schedule 05, Attachment 01 for the continuity schedule.

b) The 2018 OM&A portion of pension contributions approved by the OEB was $16,072,000. The actual 2018 OM&A portion of pension contributions made by Hydro One were $11,905,520.

c) No. The consolidated Hydro One Limited financial statements disclose the total pension plan contributions. The contributions are aligned with the pension valuation considered in this Application.

OEB INTERROGATORY #220

Reference:
H-01-01 p.13-14

Interrogatory:
At the above reference, Hydro One describes its in service capital additions variance account.

a) Please provide a table that compares the approved in service capital additions for 2016, 2017 and 2018 compared to the actual in service capital additions for the same period.

b) Can the actual in service capital additions be reconciled to the audited financial statement of each respective year (i.e. the property plant, and equipment note)? If so, please provide the reference to each. If not, then please explain why the capital additions presented in the note disclosure referenced above would not tie to the in service additions used for the purposes of calculating a balance for this DVA account?

Response:
a)

	($ millions)		
	2016	**2017**	**2018**
Hydro One Transmission In-service Capital Additions (Actual)	910.2	872.2	1,160.4
Hydro One Transmission In-service Capital Additions (Approved)	911.7	867.7	1,178.4

b) No, in-service capital additions are not reported in Hydro One Transmission's audited financial statement. The consolidated Hydro One Management Discussion & Analysis (MD&A) discloses a consolidated in-service capital additions figure for the Company (which includes Hydro One Transmission).

OEB INTERROGATORY #221

Reference:
H-01-01 p.15, H-01-02 p.12-14

Interrogatory:
At the above references, Hydro One describes its OPEB cost deferral account and its proposal to continue to capitalize the impacted OPEB costs for regulatory purposes.

a) In EB-2017-0338, Hydro One indicated that it expected the impact of the new ASU 2017-07 to be $11 million for 2018. However a balance of $22.5 million related to 2018 is currently being tracked in this account as at December 31, 2018. Please explain the significant difference compared to what was forecast in the EB-2017-0338 proceeding.

b) Can the $22.5 million be directly agreed to the underlying OPEB valuation for 2018? If not, please explain why.

c) Is there an estimated return component on the impacted costs that is also being tracked in this account? If so, how much of the account relates to this.

d) Why is Hydro One the only utility out of all of the US GAAP based utilities that are regulated by the OEB which is seeking this additional relief related to the adoption of ASU 2017-07.

e) If the OEB does not approve the continued capitalization of the impacted costs, nor does it approve the continued use of this deferral and variance account, how does Hydro One propose to deal with the disposition of the existing balance within this DVA account.

f) Please explain why Hydro One believes that rate payers would benefit from the continued capitalization of the impacted costs when they will end-up paying more for these costs over the long-term (due to the return that will be attached to them).

g) Please provide Hydro One’s forecast of the impacted costs for 2019, 2020, 2021, and 2022. What is the basis of the forecast for each year?

Response:

a) There was a significant increase in the non-service costs related to the component of OPEBs in 2018 due to a true-up of long-term disability (LTD) related costs, which was not previously forecasted. This accounts for the variance.

b) Yes. The basis is the sum of the Non-Service Cost components in the OPEB valuation for 2018. This is allocated to Transmission, Distribution and Other. $22.5 million is the amount allocated to Networks Transmission that would have been capitalized.

c) No, an estimated return component is not being tracked in this account.

d) Hydro One is not in a position to comment on the accounting policies and the resulting impact for any other USGAAP based utilities regulated by the OEB. Hydro One states that in the United States, FERC has issued guidance which allows utilities under USGAAP to continue capitalizing the impacted costs.

It should also be noted that the OPEB non-service cost deferral account was approved by the OEB in EB-2017-0338 and EB-2018-0130 for Hydro One Networks Transmission and EB-2017-0049 for Hydro One Networks Distribution to capture the financial impacts associated with the change to the US GAAP accounting standards related to the accounting of pension and other-post employment benefits.

e) If the OEB does not approve continued capitalization, nor the continued use of this deferral account, Hydro One proposes to dispose of the accumulated balance from 2018 and 2019 tracked in this account specifically for Hydro One Transmission in a similar manner of disposition to other deferral and variance accounts.

More importantly, Hydro One notes that it expects the OEB to allow recovery of the component of the non-service costs previously capitalized, as part of OM&A. Therefore resulting in a higher OM&A ask in the current and future rate applications. This will result in increased rates due to the higher OM&A and disposition of the deferral account. Please refer to Exhibit I, Tab 01, Schedule OEB-206 part b).

f) The portion of the costs that were historically capitalized, resulted in an accurate depiction of the true cost of capital assets, as all relevant labour costs of employees involved in building and developing assets were allocated to those assets and recovered over the useful life of those assets. Those assets provided benefits to ratepayers. Likewise, the portion of the costs that were historically expensed (OM&A expense) resulted in allocation of all relevant labour costs of employees involved in conducting periodic activities to be charged to that particular period, as ratepayers benefitted from these activities. Therefore, the appropriate allocation of relevant costs (including labour costs impacted by ASU 2017-07) between capital and OM&A results in matching the costs to the period in which ratepayers benefit from such costs.

g) The forecast provided by the Actuaries in December 2017, Hydro One's forecast of impacted costs is as follows (specifically the amount in question is called 'OPEB Deferral Account (non-service cost)'):

OPEBs	**2019**	**2020**	**2021**	**2022**
Amounts included in rates:				
OM&A	**15**	**16**	**15**	**15**
Capital (Service Cost)	16	18	20	20
OPEB Deferral Account (non-service cost)	19	21	23	23
Capital + OPEB Deferral Account	**35**	**39**	**43**	**43**
Forecast OPEB	**50**	**55**	**58**	**59**

OEB INTERROGATORY #222

Reference:
H-01-02 p.9-12

Interrogatory:
At the above reference, Hydro One is proposing an alternate methodology to track its accrual vs cash differential related to its OPEB costs. It proposes an alternate methodology on the basis that it capitalizes a good portion of its OPEB costs, which is not contemplated by the methodology that is prescribed in the OEB's Report on the Regulatory Treatment of Pension and OPEB costs (the Report).

a) Although the Report indicates that a utility may propose an alternate methodology in the event that they capitalize a material portion of its OPEB costs, it further clarifies that there needs to be sufficient incremental value to warrant the added complexity of tracking amounts that are capitalized separately. To that end, please explain what Hydro One believes is the incremental value that is being achieved through its alternate methodology to warrant the additional complexity.

b) Hydro One's alternate methodology proposes to separately track the depreciation associated with capitalized OPEBs. How will the OEB be able to assess the prudence of such a balance when it will be subject to internal tracking by Hydro One and there will be no external support for the balance that the OEB can rely on?

c) Please clarify if the depreciation on capitalized OPEBs represents the depreciation on the cumulative capitalized OPEBs to date or the depreciation associated with OEPBs that have been capitalized from the effective date of the OEB's policy and forward. If it is only proposing to use the OPEB depreciation associated with OPEB costs that have been capitalized from the effective date of the OEB policy and forward, please explain why it believes that such treatment is appropriate and consistent with what the OEB Report is trying to achieve.

d) Based on Hydro One's alternate methodology, what would be the amount that is tracked in the tracking account and the related carrying charges be as at December 31, 2018. What would it be under the default methodology of the Report?

e) Please prepare a table that compares the accrual vs cash differential related to Hydro One's OPEBs for each year of the period 2019-2022 under the default approach that is prescribed by the Report compared to the alternate approach that Hydro One is proposing.

f) Under Hydro One's alternate approach, is it proposing to use the same interest rate as prescribed in the Report?

<u>Response:</u>

a) The Report outlines the intent of the accrual vs cash differential variance account as follows:

> *"Where pension and OPEB amounts collected in rates are higher than payments made by the utility, current ratepayers are in effect lending money to the utility to fund future obligations."(pg. 10)*

> *"As current ratepayers are in effect lending money to the utility to fund future obligations, the tracking account option would provide the OEB with flexibility to ensure that the value being returned to ratepayers is fair, that it reasonably approximates what the utility would pay for a loan made against its borrowing capacity, and that is within the utility's debt capacity." (pg. 10)*

> *"Therefore, where the amount collected in rates exceeds the monies paid out by a utility for its pension and OPEB plans, ratepayers should be paid a return on the money they have "lent" the utility." (pg. 11)*

As summarized above, the intention of the accrual vs cash payment differential account is to provide ratepayers with a return on the money they have "lent" to the utility in so far as the amount collected in rates exceeds the payments made by the utility. The proposed alternate methodology accounts for the treatment of OPEB costs recovered in rates as capital and OM&A. In light of the fact that a material portion of Hydro One's OPEB costs are <u>not</u> recovered through OM&A, the alternative methodology therefore accurately depicts the money "lent" to the utility when compared to the assumption that the total gross accrual cost is recorded in OM&A. Therefore, the alternative methodology is necessary to achieve the intention of the accrual vs cash payment differential account without penalizing the utility unfairly. Hydro One believes that there is incremental value to applying the alternative methodology given the materiality of the difference arising from the two calculations [see response (e) below]. The consideration of the alternative methodology is in line with the OEB's mandate to allow utilities to earn a fair return. Further discussion of the account details can be found in Exhibit H, Tab 1, Schedule 2.

b) Consistent with all other Regulatory balances, Hydro One disposes only of Audited Actual balances that are subject to audit as part of the stand-alone carve out financial statements.

c) The account will capture the depreciation associated with the OPEBs that have been capitalized from the effective date of the account as noted in the Report.

> *"This account will track the differences between the forecast accrual amounts recovered in rates and the actual cash payments made for both pension and OPEBs in one account, on a go-forward basis from the date the account is established. The account will not capture differences that occurred in the past…" (pg. 20)*

As noted above, the Report defines the account as tracking the difference between the forecast accrual amounts recovered in rates and the actual cash payments and as such is referring to the accrual amounts relevant to the year of implementation (2018) and subsequent years, as the costs for such years would be known on a forecast basis. Furthermore, it is Hydro One's view that instituting a future variance mechanism relating to an incurred cost of a prior period may be retroactive ratemaking and is not the intention of the variance account.

d) Please see response to part e), below.

e) The table below shows the accrual vs cash differential and the carrying charges tracked for the years 2018 – 2022 based on the default approach and the proposed alternate approach. The carrying charge line represents the figures that would be captured in the OPEB asymmetrical carrying charge account in each year. For years

2019-2022 the amounts are based on forecast OPEB costs provided by the Actuaries in December 2017.

	2018	2019	2020	2021	2022
Default approach					
accrual vs cash (cumulative)	29	53	79	106	133
Carrying charge	0.8	1.5	2.3	3.1	3.8
Alternate approach					
accrual vs cash (cumulative)	(0.2)	(9.4)	(19.4)	(30.3)	(40.3)
Carrying charge	-	-	-	-	-

f) Yes, Hydro One is proposing to use the CWIP rate as prescribed in the Report.

OEB INTERROGATORY #223

Reference:
H-01-02 p.7

Interrogatory:
At the above reference, Hydro One is proposing a new earnings sharing mechanism, effective January 1, 2020, to record any over earnings realized during any year of the three-year term 2020-2022.

a) Please confirm that the basis of the ESM calculation will be the annual RRR 2.1.5.6 filing.

b) Please confirm that the account is asymmetrical in that it will only track over-earnings.

Response:
a) Hydro One proposes to use a methodology which is similar to what is outlined in the annual RRR 2.1.5.6 filing. As stated in Exhibit A, Tab 4, Schedule 1 under section 2.1 titled "Earnings Sharing Mechanism (ESM)" the calculation of actual ROE will use the OEB approved mid-year rate base for that period to avoid double counting with amounts in the proposed in-service variance account. As discussed in Exhibit I, Tab 05, Schedule CME-6 the ROE calculation is to be normalized for revenue impacting items that are recorded in the year which relate to prior years to normalize the in-year net income.

b) Confirmed.

OEB INTERROGATORY #224

Reference:
H-01-02 p.6

Interrogatory:
At the above reference, Hydro One is proposing to continue the in service capital additions variance account to record the net cumulative variance over 2020-2022 between OEB approved in service additions and actual.

a) It is not clear from the description provided whether the proposed new account will also capture the difference between approved and actual in-service additions for the bridge year 2019? If Hydro One is not proposing to include 2019 within this account, please explain why it feels that this would be appropriate.

Response:
The approval of the 2020 rate base figure in this Application would inherently include the 2019 in-service additions forecast; therefore, Hydro One is proposing that for 2020, the account should consider both 2019 and 2020 in-service additions on a cumulative basis. This is consistent with the mechanics of a similar account previously approved by the OEB as part of the last transmission application (EB-2016-0160).

OEB INTERROGATORY #225

Reference:
I2-02-01 p.3 of 5

Interrogatory:
At the reference above, it is stated that:

Hydro One is proposing to update the definition of billing demand for the Line and Transformation Connection services to reflect the changes in the embedded generation market over the years, such as inclusion of energy storage facilities.

The "Embedded Generation" section in the proposed 2020 Ontario Uniform Transmission Rate Schedules (Exhibit I2, Tab 6, Schedule 2, Attachment 1) has also been updated to align with the changes in billing demand for the Line and Transformation Connection services.

a) Please explain why the proposed changes to the definition of billing demand for the line and transformation connection services and the changes to the definition of embedded generation are necessary.

b) Please discuss whether or not there are costs shifted to other customers if existing customers with energy storage facilities and/or solar generators (the individual inverter unit capacity is one MW or higher) are continuing to be billed on a net load basis.
   i. If so, please quantify the shifted costs.
   ii. If not, why not.

c) Please explain when and how the original definitions were determined.

d) Did Hydro One consult customers with energy storage facilities and/or solar generators (the individual inverter unit capacity is 1 MW or higher) about the proposed changes? If so, what are the customers' feedback on the proposed changes? If not, why not?

e) Please estimate the bill impact for a customer with energy storage facilities or solar generators before and after the proposed changes using the proposed 2020 UTRs.

Response:

a) The definition of billing demand for the line and transformation connection services and embedded generation in the current Uniform Transmission Rate ("UTR") Schedules have not been updated since 2005[1]. The proposed changes in wording clarify and reflect Hydro One's interpretation of these definitions in the data provided to the IESO for transmission billing purposes.

b) It is Hydro One's interpretation and practice to include customers with energy storage facilities and/or solar generators (the individual inverter with capacity is 1 MW or higher) in the data provided to the IESO for billing Line Connection and Transformation Connection customers on a gross load basis as per the approved UTR tariff. As discussed, in part (a), the proposed wording changes simply clarify and reflect Hydro One's interpretation. There will be no cost shifting as there will be no change in Hydro One's practice.

c) The original definitions were approved in the OEB's May 26, 2000 Decision on Hydro One's Transmission Application (RP-1999-0044). Section 3.2 of this Decision provides the rationale.

A 2 MW limit for renewable generation was added and was approved by the OEB in the Transmission System Code Phase 1 Policy Decision with Reasons (RP-2002-0120, issued June 8, 2004). Section 5.2 of this Decision provides the rationale. Subsequently, the UTR Schedule was updated under EB-2005-0241.

d) Hydro One did not consult customers about the proposed changes in wording. As discussed in parts (a) and (b), these wording changes simply clarify and reflect Hydro One's interpretation and practice. Customers will not be impacted by these changes.

e) Does not apply. Please see response in part (b).

[1] OEB Decision and Order EB-2005-0241 issued December 8, 2005

OEB INTERROGATORY #226

Reference:

I2-02-01-01 p.1 of 11
EB-2016-0160, Submissions of CME, p.26-27

Interrogatory:

At the first reference above, it is stated that:

In its October 11, 2017 Decision in Proceeding EB-2016-0160, the Board directed Hydro One to provide a report in its next Transmission rates application that addressed Canadian Manufacturers and Exporters' ("CME") concern about the Network Service Charge ("NSC") that applies to manufacturing or industrial customers who shift their operations to outside of the 7 AM to 7 PM timeframe when the system peak occurs after 7 PM. In response to the Board's Decision, this Exhibit examines the issue of modifying the existing NSC determinant to address CME's concern.

At the second reference above, it is stated that:

CME requests that the Board direct Hydro One to present a report in the next transmission case that addresses how the NSC determinant can be modified to ensure that manufacturing or industrial customers who shift their operations to outside of the 7 a.m. to 7 p.m. window, are not penalized when a system peak occurs after 7 p.m. We would request that the report consider:

i. Whether the NSC determinant should only be based on manufacturing and industrial customer's non-coincident monthly peak demand between 7 a.m. and 7 p.m. on IESO business days, and not in any way determined by the customer's demand that is coincident with the monthly system peak;
ii. Whether there should be a separate NSC determinant that is only applicable to manufacturing industrial customers; and
iii. Whether additional steps can be taken by Hydro One to assist manufacturing and industrial customers to ensure that they not inadvertently operate during a monthly system peak that occurs outside of 7 a.m. to 7 p.m.

a) Please state where in the current evidence Hydro One has addressed CME's concerns referenced above.

b) Please add, if any, the system peaks outside the 7AM to 7PM period for 2018 to Table 1 in Exhibit I2-2-1, Attachment 1.

<u>Response:</u>

a) Items (i) and (ii), as listed in the interrogatory, have been directly addressed in Exhibit I2, Tab 2, Schedule 1, Attachment 1, Section 4.4.

As for item (iii), customers can forecast system peak times based on historical actual and future forecast system peak information on the IESO's Public Reports website to avoid operating during system peak hour.

The historical data shows that when the system peak occurred outside the 7AM to 7PM period, it was always at hour 20 during the months of February/March/April and/or October. In light of this, customers may consider starting their operations one hour later during these months. Hydro One notes that, as discussed in Exhibit I2, Tab 2, Schedule 1, Attachment 1, page 11, the two industrial customers negatively impacted in 2012 to 2015 appear to have modified their behaviour in 2016 and 2017 to avoid system peak outside the 7AM to 7PM period.

b) Below is the referenced table updated to include system peaks outside the 7AM to 7PM period for 2018:

Year	Number of Occurrences (Annually)	Month and Hour (local time)
2012	4	February, hour 20
		March, hour 20
		April, hour 20
		October, hour 20
2013	3	March, hour 20
		April, hour 20
		October, hour 20
2014	4	February, hour 20
		March, hour 20
		April, hour 20
		October, hour 20
2015	4	February, hour 20
		March, hour 20
		April, hour 20
		October, hour 20

Witness: Clement Li

Year	Number of Occurrences (Annually)	Month and Hour (local time)
2016	2	April, hour 20
		October, hour 20
2017	3	March, hour 20
		April, hour 20
		October, hour 20
2018	2	March, hour 20
		April, hour 20