F- 12

EB-2016-0160

Hydro One Networks Inc. Transmission Application for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018

VULNERABLE ENERGY CONSUMERS COALITION

("VECC")
CROSS-EXAMINATION
COMPENDIUM PANEL 5
PLANNING

December 1, 2016

TAB 1

As illustrated in Figure 1, in the ARA methodology, different sources of risk are considered in developing a multi-faceted picture of asset risk.

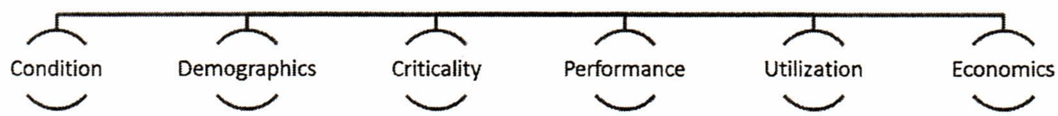


Figure 1: Factors used to evaluate asset risk

In assessing asset needs, planners also consider other factors such as environmental risks and requirements, compliance obligations, equipment defects, health and safety considerations and customer needs and preferences. Planners then make recommendations regarding what investments should be made within an identified timeframe. To clarify, the ARA is one step in the asset planning process; it does not replace decisions made by qualified engineers in conjunction with physical inspections.

2.1.1 Asset Condition Risk

Asset condition risk relates to the increased probability of failure that assets experience when their condition degrades over time, which is based on empirical data. Asset condition is defined using different criteria, depending on the asset. For example, the condition of a transmission station transformer is measured by visual inspections and analysis of the oil within the transformer. The condition of a wood pole is measured by a visual inspection, a sounding test, and if required, a boring test. While methods to evaluate condition vary from asset type to asset type, the condition of all assets of a given type is evaluated consistently. Assets of a given type that have a relatively high condition risk are candidates for refurbishment or replacement.

While an economic evaluation can identify assets that are candidates for replacement, more typically, the evaluation assists in selecting the best form of remediation for assets already deemed to be candidates for refurbishment or replacement.

2.2 ARA Data

Asset condition data is collected during routine maintenance, inspections and testing. For each specific asset, information on condition, performance history, utilization, criticality and other non-condition characteristics is compiled into a database for planning purposes. Improving the quality and quantity of this data is an ongoing objective for Hydro One.

3. DEVELOPMENT, OPERATIONS, AND COMMON CORPORATE NEEDS

Development activities focus on customer-specific and system-level needs, which are discussed in Exhibit B1, Tab 2, Schedules 2 and 3. In Operations, asset needs are driven by the lifecycle of facilities and tools, which are primarily information technology ("IT") tools, as well as compliance requirements. Other determinants include the requirement to facilitate renewable generation and conservation initiatives.

Common Corporate asset needs are determined by organizational and compliance requirements. Fleet, real estate and facilities requirements are assessed annually between the relevant organizations within the company. There are compliance requirements that drive asset needs for fleet, real estate and facilities, but the primary determinants are the support requirements of the Sustainment, Development, and Operations workstreams. IT needs are driven by corporate requirements and compliance requirements, such as the NERC Critical Infrastructure Protection Standards.

Witness: Chong Kiat Ng

Ontario Energy Board (Board Staff) INTERROGATORY #014

Reference:

Exhibit B1/Tab2/Sch 4/p. 7 - Section 3.2: Reliability Risk Modeling Approach.

"Reliability risk is modelled using the relationship between asset demographics, historical asset failures and the impact that equipment has on reliability. Hydro One's risk model focuses on lines, transformers and breakers, due to their large contribution to reliability risk and criticality to the system. Calculating reliability risk based on the interruption durations attributable to these asset classes creates a measure of the substantial portion of the reliability risk on the transmission system.

The output of the risk model is a measure of the system reliability risk resulting from planned investments relative to a baseline. The model considers both the expected impact of asset replacement and the continued aging and deterioration of existing assets."

Interrogatory:

a) Please confirm that Hydro One's risk model only takes into account lines, transformers and breakers and that no other asset classes are considered by Hydro One when calculating reliability risk.

b) Please identify if this is Hydro One's first Transmission Cost-of-Service Application and Evidence Filing to employ this risk modeling approach.

c) Has Hydro One back-tested or "back-cast" its reliability risk model to validate modeled risk projections against actual reliability and outage performance? If yes, please provide the results of these back-tests.

d) Does Hydro One use the risk model output to develop capital investment budgets? If yes, please explain in detail how the risk model output is used and at what stage of the capital planning process.

e) Please provide Hydro One's methodology and quantified model outputs that were used to assess the system reliability risk impacts of the capital investments proposed in this filing.

f) If the risk model output does not identify individual capital projects, how does it provide a meaningful indication of the reliability risk mitigation effectiveness of different levels of capital investment? Please explain in detail and include quantified examples.

Witness: Mike Penstone

g) Has Hydro One used asset demographics to determine which assets need to be replaced in the absence of asset condition assessment and/or performance data? If yes, please identify which of the projects identified in this application are driven primarily by asset demographics and provide Hydro One's rationale for not field-verifying the condition/performance of these assets prior to including these projects in the present filing.

Response:

a) Confirmed. This is based on a study covering 10 years of reliability data verifying that lines, transformers and breakers are the most impactive asset types to reliability.

b) This is the first time Hydro One has introduced reliability risk model. This model is new and will improve over time. Similar methodology is being developed and used in the UK under the Office Of Gas and Electricity Markets (OFGEM).

c) No. Hydro One has not back-tested or back-cast its reliability risk model.

d) No, the risk model does not set the capital budget. Hydro One uses this model as part of its investment planning process as described in Exhibit B1, Tab 2, Schedule 4. As indicated on page 1, line 23, the process starts with "...review of the system, with a focus on reliability performance and reliability risk....". Hydro One establishes a baseline of reliability risk at the onset of investment planning exercise. This is achieved by using the transformer, conductor and breaker demographic prior to undertaking capital investments, and calculating the reliability risk. After an optimized plan is developed, the renewed transformer, conductor and breaker demographics are used to recalculate reliability risk. The before and after capital investment reliability risk provides a measurement to gauge the impact of its investments on future transmission system reliability.

e) The methodology is discussed in Exhibit B1, Tab 2, Schedule 4, Attachment 1. Details describing how this model is derived and its application are provided. The output of this model is shown as Table 1, in page 8 of B1-02-04. Refer to Staff IR 15 for calculation details.

f) Reliability risk is an outcome measure, as described in Exhibit B1, Tab 2, Schedule 4, used to gauge the impact of Hydro One's investment plan on future transmission system reliability. The model is not intended to be used to determine individual capital projects. It provides a meaningful directional relative comparison to demonstrate that a given level of capital investment reduces reliability risk.

demonstrates the calculation of the total risk by weighing the relative risk of the asset type by the SAIDI interruption data and then summed up over all the assets.

b) As stated, the columns in Table 1 presenting the asset-specific relative risks are based on the computed overall probabilities of failure. It does not include outage interruption data (SAIDI) and is based on historical replacement rates. Note that in the case of multiple supply delivery points, an equipment failure will not result in SAIDI, CAIDI implications but will increase the risk of reliability while under the single supply condition.

c) The reliability risk is a function of asset demographics and hazard curves, which are non-linear. As such, the relationship between capital investment level and relative change in reliability risk is also non-linear. However, there is a positive correlation, a higher level of investment leads to more improvement in reliability risk.

d) Yes, Hydro One evaluated alternative investment scenarios, which were discussed as part of the customer engagement included in Exhibit B1, Tab 2, Schedule 2, Attachment 2, Transmission Customer Engagement: Investing for The Future, Page 23. Three indicative investment scenarios over a 5 year planning period were discussed. Respective reliability risk associated with Scenario 1, 2 and 3 are increased by 9%, increased by 2% and reduced by 10%.

e) Yes. Hydro One has prioritized its proposed investments at the corporate level. The prioritized project list takes the form of the optimized portfolio of investments filed in this application. In the event of a reduced approved level of capital investment, Hydro One will reduce its work program using the optimization criteria (Exhibit B1, Tab 2, Schedule 7).

The expected outcome is an increase in reliability risks and potential future deterioration in actual reliability performance. In this scenario, a load serving transformer in poor condition is ranked the lowest and may not get replaced, effective placing it under run to failure option, which is highly impactive to reliability.

summarizes the expected relative decrease in risk, for each critical asset class and for the system as a whole, as a result of the 2017 and 2018 investment plan. For comparison the table also provides the relative increase in risk which will occur if no assets were replaced in the two year period.

Table 1: Relative Change in Reliability Risk

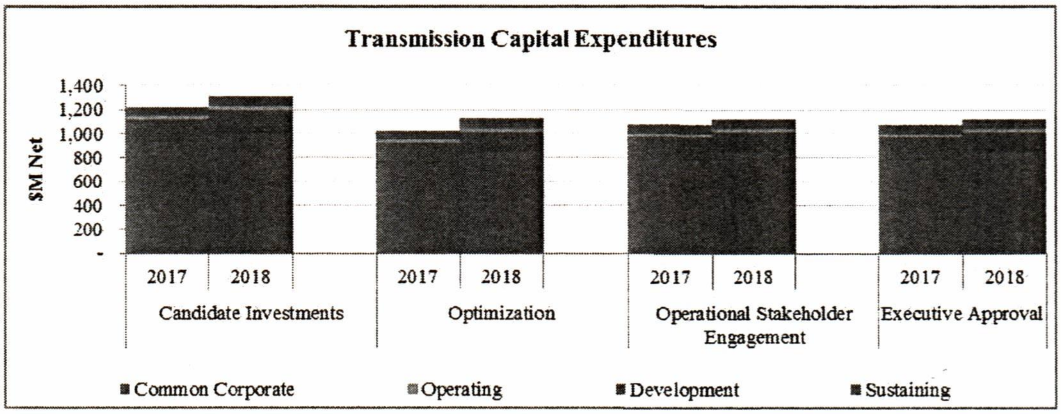
	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018, as per proposed investment	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018, without investment	% of Interruption Duration*
Lines	-2%	11%	69%
Transformers	-9%	14%	9%
Breakers	1%	17%	6%
Other[1]	-	-	16%
Total*	**-2%**	**10%**	

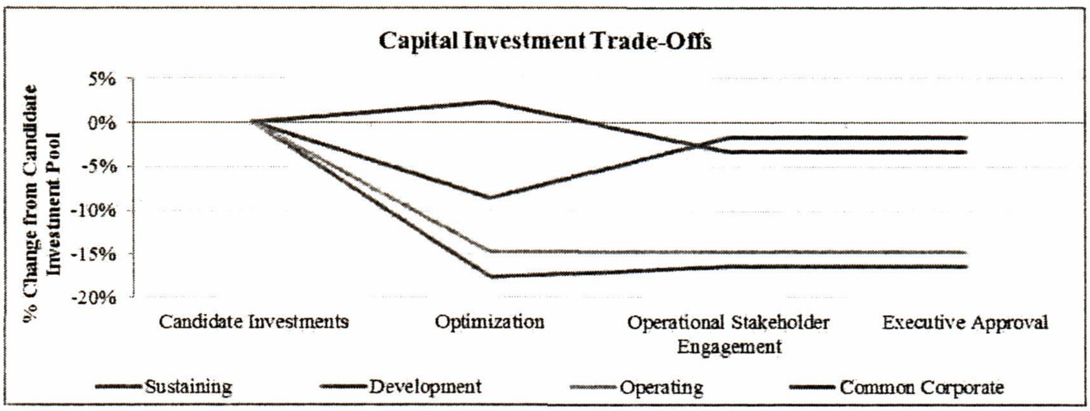
* Total is calculated by weighting the change in risk by the asset class' contribution to interruption duration.

4. ASSET CONDITION

At a fleet level, asset age is used as a proxy for the probability of asset failure and the need for replacement. Quantitative data demonstrates the historical relationship between asset age and failure. This data has informed Hydro One's reliability risk model. However, as noted above, specific investment decisions are not based on age, but through the Asset Risk Assessment process described above and in Exhibit B1, Tab 2, Schedule 5.

[1] Represents all other assets; risk is assumed to be flat over the investment planning horizon for these assets


Transmission Capital Expenditures
$M Net
1,400
1,200
1,000
800
600
400
200
-
2017
2018
Candidate Investments
Optimization
Operational Stakeholder Engagement
Executive Approval
Common Corporate
Operating
Development
Sustaining


Capital Investment Trade-Offs
% Change from Candidate Investment Pool
5%
0%
-5%
-10%
-15%
-20%
Candidate Investments
Optimization
Operational Stakeholder Engagement
Executive Approval
Sustaining
Development
Operating
Common Corporate

UNDERTAKING – TCJ2.20

Undertaking

To respond in writing to the follow-up questions that Ms. Grice asked about the Reliability Model, the consultation, and how that has affected the overall plan re Exhibit I, Tab 11, Schedule 2; Exhibit A, Tab 3, Schedule 1, Table 2, page 7; Exhibit B1, Tab 3, Schedule 1, page 1, Table 2; and Exhibit B1, Tab 2, Schedule 2, Attachment 2.

Response

Part 1:
What does the Risk Reliability Model cover, just Sustainment Capital as indicated in response to part a) or any other classes of Capital Investment as well e.g. Control Centre?

The reliability risk model is an outcome measure to gauge the impact of investments on future transmission reliability performance. It is based on asset hazard functions, demographic profiles, proposed investment plan and three asset classes that are most impactive to SAIDI performance. Please refer to Exhibit B1, Tab 2, Schedule 2, Attachment 2, Page 13. These three classes of assets are currently in-service, and hence the outcome measure is affected by Sustainment Capital investment. Investments in these three asset classes will help Hydro One to maintain its system reliability performance; hence, the reliability risk model is focusing in on these three asset classes.

Part 2:
Of the three Investment Scenarios Attachment 2, Ipsos Report page 24 presented to the Consultation Exhibit B1, Tab 2, Schedule 2, it says on Page 14

> "the majority of participants would be willing to support the investment required to at least maintain the current level of reliability risk. The general sentiment, overall, was that the right balance between reliability risk and rates is somewhere between Illustrative Scenario 2 (6.3% rate increase for an essentially unchanged reliability risk) and Scenario 3 (6.8%rate increase for approximately 10% improvement in reliability risk)."

1. Which (Sustaining?) Investment Scenario and Rate Increase presented in the Consultation is closest to
   a) the participants expressed preference and
   b) Hydro One proposal Preferred Scenario as shown Table 2

Witness: Mike Penstone/Chong Kiat Ng

TAB 2

School Energy Coalition (SEC) INTERROGATORY #021

Reference:
B1/2/6, p.7-66

Interrogatory:
For each major asset type, please provide a table showing the number of assets in each of the following categories, i) very low risk, ii) low risk, iii) fair risk, iv) high risk; and v) very high risk.

Response:
The fleet level condition assessment distribution of station's major asset types is as follows:

Asset Type	Very Low Risk	Low Risk	Fair Risk	High Risk	Very High Risk
Transformers	323	224	63	97	14
Circuit Breakers	2292	1111	671	431	38
Protection Systems	4357	3994	484	1936	1331

The fleet level condition assessment distribution of Line's major assets is as follows:

Asset Type	Low Risk	Fair Risk	High Risk	Require Assessment
Conductors (km)	12,000	6,000	2,700	9,300
Wood poles	29,820	8,400	1,260	2520
Underground Cables (km)	197	59	11	3

Witness: Chong Kiat Ng

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #010

Reference:
Exhibit B1/T2/S6/pgs. 9-

Interrogatory:

a) Please amend Tables 3,5,8,9,10,11 (as adjusted for question 9 above), 12 and 13 to show the actual and forecast capital expenditure for these activities.

b) Please include the years 2019 through 2021 (as per Table 5/1 Summary of Transmission Capital Budget (A/T3/S1/pg.13/B1/T3/S1/Table 1) to the amended tables

c) Please reconcile (if different) the capital budgets for Table 3 et al and the amounts shown in the Summary Table 5.

Response:

a) Please refer to Exhibit I, Tab 6, Schedule 20 for updated Tables 3, 5, 8, 9, 10, 11, 13.

Updated Table 12 below:

Table 12: Insulator Portfolio Replacement

Insulator Portfolio	Historic				Bridge	Test	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
# of circuit structures	210	433	233	155	2100	4030	3880
% of Fleet	0.15%	0.3%	0.2%	0.1%	1.4%	2.7%	2.6%
Capital ($M)	3.3	6.9	3.8	2.8	26.1	63.9	61.4

b) & c) Hydro One has provided forecasts that meet the filing requirements and also provide the full detail relating to the costs for which rate recovery is sought in this application (Test Years 2017 and 2018).

Table 11: Steel Structure Replacement

Steel Structure Portfolio		Historic			Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
# of Renewal	228	235	121	300	462	1250	1600
% of Fleet	0.4	0.5%	0.2%	0.6%	0.9%	2.4%	3.1%

The capital investment in the test years is an increase over historic levels. The strategy to manage the fleet of steel towers is a combination of planned replacements, component refurbishment and tower coating. The number of towers that have been refurbished, coated, or replaced over the past 10 years has been very low. As a result of recent condition inspections and tower coating studies the rapid deterioration of steel structures in highly corrosive areas needs to be addressed with an increase in the fleet renewal rate. Hydro One plans to undertake an aggressive tower coating program to sustain these assets. Tower coating has been identified as the preferred alternative as it has a significant life cycle cost advantage and has less impact to the system as circuit outages required for coating are minimal.

3.4 Transmission Lines Insulators

3.4.1 Asset Overview

Transmission line insulators are an integral component of the transmission system. They mechanically support and electrically insulate the conductor from the structure and must provide sufficient dielectric strength to prevent short circuits to ground. There are approximately 420,000 insulator strings in Hydro One's overhead transmission network. They are assessed through visual inspection, infrared thermography and in-situ live-line electrical testing. Insulators are categorized into three types; porcelain, glass and polymer as described below and depicted in Figure 40.

Condition

Transformer condition is a leading predictive indicator of equipment reliability. Condition is primarily based on transformer oil testing (dissolved gas analysis, furan, standard oil testing), power factor testing, and general findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, heat from transformer loading, exposure to oxygen, moisture contamination, and damaging acids in the insulating oil as a result of insulation aging. Degradation is irreversible and transformer replacement is the only viable solution.

Based on the latest analysis, 15% of Hydro One's transformer population is rated high or very high risk, as outlined in Figure 5.

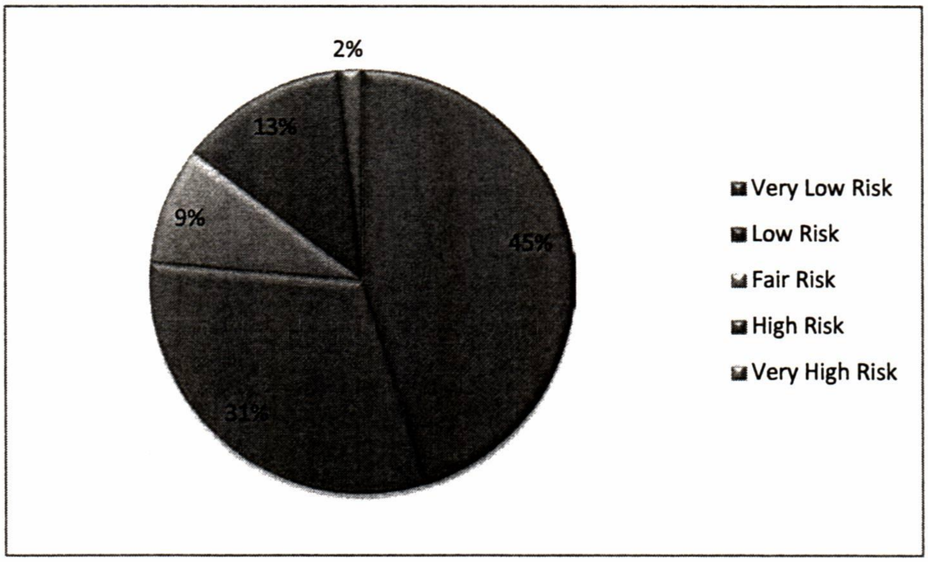


Figure 5: Transformer Fleet Condition Assessment

To date, the sustaining replacements have addressed many of the transformers with the highest probability of failure, along with a number of maintenance activities that have

Table 3 below provides the historic replacement rate of transformers.

Table 3: Transformer Replacement Rate

Transformer Portfolio	Historic			Bridge	Test	
	2013	2014	2015	2016	2017	2018
# of Replacements	15	24	21	19	27	22
% of Fleet	2.1%	3.3%	2.9%	2.6%	3.7%	3.1%

The capital replacement rate in the test years is needed to manage reliability and reliability risk through the test years. Transformers are a major element in ensuring a reliable bulk electricity system. Transformer failures directly affect load customers, either through loss of load or increased risk resulting from the loss of system redundancy, until such time the transformer can be replaced. Maintaining the fleet in an adequate condition preserves reliability consistent with good utility practice and regulatory obligations.

2.2 Circuit Breakers

2.2.1 Asset Overview

Hydro One has 4,543 circuit breakers in service, as outlined in Table 4. High voltage ("HV") breakers are installed in 500 kV, 230 kV or 115 kV positions, and medium voltage ("MV") breakers are installed at 44 kV, 27.6 kV, 13.8 kV or 12.5 kV positions.

arc flash and electrical burn hazards in the event of equipment failure. These risks become more significant as the equipment ages.

- Technical Obsolescence - Many breakers are no longer supported by vendors and aftermarket parts are not available or cost effective. This is a significant factor for air blast circuit breakers, some first generation SF6 circuit breakers, and certain types of metalclad and oil circuit breakers.
- Equipment Operations - Breakers that have exceeded their expected service life in terms of number of operations, have parts that are significantly worn, and are considered for replacement. Due to their frequent operation, this is most typical of capacitor and reactor breaker positions.
- Environmental Impact – Minimizing SF6 emissions and their resultant impact as a greenhouse gas to the environment is considered in the replacement or refurbishment plans for SF6 breakers.
- System Evolution – Load growth and renewable generation connections may lead to increase in short-circuit requirement that is beyond the functional capability of existing breakers.

Table 5: Circuit Breaker Replacement Rate

Circuit Breaker Portfolio	Historic			Bridge	Test	
	2013	2014	2015	2016	2017	2018
# of Replacements	57	83	31	43	66	132
% of Fleet	1.2%	1.8%	0.7%	0.9%	1.5%	2.9%

The capital replacement rate in the test years is an increase over historic and bridge levels. Continued renewal of the fleet at an increased rate is required to maintain system reliability performance through the test years.

Circuit breakers are a major element in ensuring a reliable bulk electricity system. Breaker failures are directly impactive to load customers, either through loss of load or planning and overall system reliability. This is a significant factor for electromechanical and solid state systems.

- Innovation – New microprocessor based protection systems have advanced monitoring and diagnostic capabilities which can provide insight into station equipment performance and early detection of problems, potentially avoiding equipment damage. Modern microprocessor protection systems can be deployed with pre-tested configuration settings to facilitate fast and efficient system protection changes to accommodate dynamic changes to the configuration of the transmission system. Extended maintenance intervals for microprocessor based systems help contain OM&A expenditures and reduce life cycle costs.

Table 8: Protection Replacement Rate

Protection Systems Portfolio	Historic			Bridge	Test	
	2013	2014	2015	2016	2017	2018
# of Protection Replacements	340	610	266	367	449	528
% of Fleet	2.8%	5.0%	2.2%	3.0%	3.7%	4.4%

On average, Hydro One has replaced 438 protection systems over 2014 and 2015 and will replace an average of 448 per year, out of 12,100, in 2016 through 2018. Protection and automation bundling approach has been used starting 2013 for any future protection system replacement with in service date planned 2015 and after.

OM&A expenditures are generally consistent year over year with minor variations attributed to time-based scheduling of preventative maintenance. Replacement of electromechanical and solid state protections with modern microprocessor based protection systems is expected to lower future maintenance costs as the new technology allows for extended maintenance intervals.

Other Influencing Factors

- Aeolian Vibration - Geographical location, line orientation and more importantly conductor tension contribute to level of vibration each circuit experiences, which directly influences the useful lifespan of a conductor. Hydro One has experienced premature conductor failures due to a combination of conductor condition and conductor fatigue due to vibration.
- Safety – Given that transmission lines operate in the public domain, additional consideration must be given to the consequence of failure and potential impact on safety of the public. Factors such as right-of-way use and proximity to road crossings are considered when assessing risk.

Table 9: Conductor Replacement Rate

Conductor Portfolio	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
KMs of Circuit Replacements	22	75	93	201	183	192	440
% of Fleet	0.1%	0.3%	0.3%	0.7%	0.6%	0.6%	1.5%

The need for capital replacement of conductors is expected to increase to an average of 1.7% or 500 circuit km annually in subsequent years, to address the deteriorating condition of the conductor. The circuits being addressed in the bridge and test years have all reached end of life verified through testing and condition assessment.

3.2 Transmission Wood Pole Structures

3.2.1 Asset Overview

Hydro One has approximately 42,000 wood pole structures. Wood has been a popular material for use in building transmission lines because of its cost effectiveness and reliability over the life of the asset. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access. These wood pole structures are utilized on 230 kV and 115 kV circuits depending on the

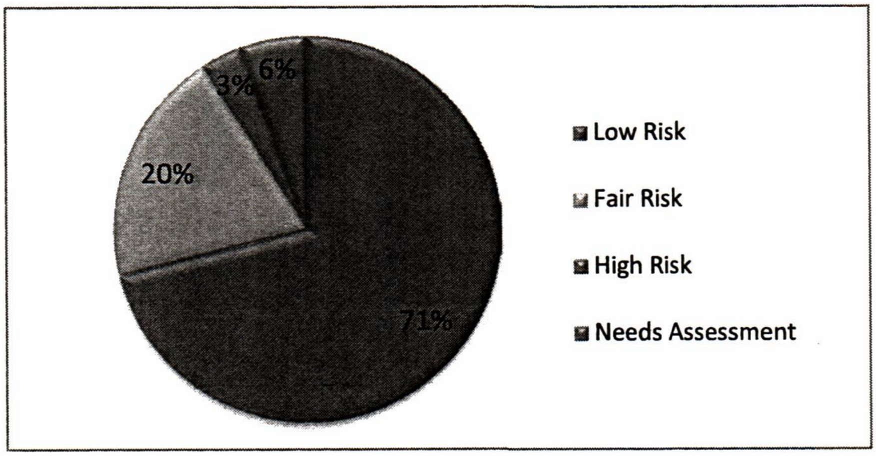


Figure 30: Wood Pole Fleet Condition Assessment

The number of poles reaching end of life identified each year through condition assessments is consistent with the current replacement rate, and hence the number of wood poles in fair and high risk condition is expected to remain stable. The number of poles replaced historically and planned for the bridge and test years is displayed in Table 10 below. As a result, reliability and safety risks will be in-line with past performance which has been improving in terms of outage frequency and duration over the past 10 years.

Table 10: Wood Pole Replacement Rate

Wood Pole Portfolio	Historic				Bridge	Test	
	2012	2013	2014	2015	2016	2017	2018
# of Replacements	763	480	897	845	850	850	850
% of Fleet	1.8%	1.2%	2.2%	2.0%	2.0%	2.0%	2.0%

The capital replacement rate in the test years remains consistent with the bridge year and historic levels. Continued renewal of the fleet at this rate has been very effective at keeping pace with the number of structures that reach their expected service life.

Table 13: Underground Cable Replacement

Underground Cable Portfolio	Historic				Bridge	Test	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Kms of Circuit Replacements	0	5.0	3.1	0	0	0	4.8
% of Fleet	0%	1.9%	1.1%	0%	0%	0%	1.8%

Hydro One is now entering into a period where the underground cable circuits are approaching their end of expected life and in order to effectively manage the underground cables continued renewal of the fleet must be maintained. There is some variability in capital expenditures year over year, which is mostly a function of the timing and magnitude of individual projects. The replacement of older oil filled cable systems with new XLPE cable systems, which have lower maintenance costs, will result in lower lifecycle costs.

OM&A expenditures are relatively stable year over year in order to carry out assessment activities to provide insight into cable condition.

Many factors drive cable replacement; the key factors include condition, performance, obsolescence, age, circuit criticality, and environmental impacts. Failure of underground cables can take significant time to repair or replace. This can place considerable strain on the system as it may restrict outages required for maintenance or repair of other equipment. Overloading other cables and related elements can place the system at risk of failure, loss of supply and blackout to the customer.

VECC Exhibit:

Asset Type	Very Low Risk	Low Risk	Fair Risk	High Risk	Very High Risk	Total	2017 Replacements	2018 Replacements	2017 & 18 Total Replacement	2 Year Rplcmt % of very high risk	2 Year Rplcmt% of very high and high risk
Transformers	323	224	63	97	14	**721**	27	22	49	**350%**	44%
Circuit Breakers	2,292	1,111	671	431	38	**4,543**	66	132	198	**521%**	42%
Protection Systems	4,357	3,994	484	1,936	1,331	**12,102**	449	528	977	**73%**	30%

Asset Type	Low Risk	Fair Risk	High Risk	Require Assessment	High risk as % of total	Total	2017 Replacements	2018 Replacements	2017 & 18 Total Replacement	2 Year Rplcmt % of high risk	% of high risk and extrapolated High risk
Conductors (km)	12,000	6,000	2,700	9,300	9.0%	**30,000**	192	440	632	**23%**	17.9%
Wood poles	29,820	8,400	1,260	2520	3.0%	**42,000**	850	850	1700	**135%**	127.3%
Underground Cables (km)	197	59	11	3	4.1%	**270**	0	4.8	4.8	**44%**	43.2%

Source: Exhibit B1/Tab 2/Schedule 6 & Exhibit I/Tab 6/Schedule 21

TAB 3

UNDERTAKING – TCJ2.12

Undertaking

To provide a response to three recommendations of the Auditor General's Report on page 251.

Response

The undertaking was to provide a summary of how three additional areas of concern cited by the Auditor General were addressed in this application. The additional areas are:

- Spare Transformers in Storage Not Aligned with Hydro One's Needs
- Data from Power Quality Meters Not Used to Help Customers Avoid Disruptions
- Weak Management Oversight Processes over Capital Project Costs

Spare Transformers in Storage Not Aligned with Hydro One's Needs

A comprehensive review of the transformer spares inventory at Hydro One's Central Maintenance Shop in Pickering has been completed. Our system of record (i.e. SAP) has been updated to reflect the outcome of review. Hydro One spare inventory management is described in to Exhibit B1, Tab 3, Schedule 2, Section 4.2.2, Spare Transformers.

Hydro One also reviewed its suite of power transformers to determine whether opportunities existed to further consolidate design and procurement standards. The review concluded that there are limited efficiencies to be gained from further standardization.

Data from Power Quality Meters Not Used to Help Customers Avoid Disruptions

Frequency and voltage fluctuations on the transmission system become a power quality event only if customers' equipment or processes are adversely affected. It is not technically possible for a utility to predict or determine whether a voltage sag event caused a PQ disruption to a customer,

The most common power quality problem that can lead to disruption of large industrial customer processes is temporary voltage sags. The impact of voltage sag depends on their magnitude and duration and the resilience of customers' equipment.

UNDERTAKING – TCJ2.14

Undertaking

To provide the number of transformers that have been included in the forecast for the test years for spares and for power.

Response

Hydro One has currently purchased the following spare units in 2016:

- 1 unit of 125 MVA, 230kV/28-28kV, step-down transformer
- 1 units of 83MVA, 230kV/44kV, step-down transformer
- 1 unit of 150MVAr, 27.6kV, dry type reactor
- 1 unit of 50MVAr, 13.8kV, dry type rector

Hydro One anticipates purchasing four (4) spare transformers in each of 2017 and 2018 to account for an average of four (4) demand failures per year as outlined in Exhibit I, Tab 1, Schedule 31. The specific type of transformers is dependent upon the actual failures.

The list of transformers identified for procurement to meet planned replacement requirements in 2017 and 2018 are outlined in Exhibit I, Tab 1, Schedule 31.

Witness: Chong Kiat Ng

available as operational spares or for emergency replacement in the event of equipment failure.

The purchase of operating spare transformers is in line with Hydro One's probabilistic approach to determine the number of spare requirements. The analysis considers performance trends and supply chain considerations of Hydro One's various power transformer types, and groups them into optimized spare cohorts to adequately cover the in-service population. The transmission operating spares requirement is intended to replenish inventory that is expected to be drawn down for future failures.

This program also covers the purchase of mobile transformers to facilitate planned outages, as well as spare breakers, and bushings that are required as operating spares in case of equipment failure.

Table 7 outlines the proposed funding for test years 2017 and 2018, along with the spending levels for the bridge and historic years.

Table 7: Transmission Station Demand and Spares ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Transmission Station Demand and Spares*	-	-	-	27.2	20.5	25.3	25.8

**Previously these amounts were recorded as Power Transformers and Circuit Breakers.*

Hydro One manages the Transmission Station and Demand Spares category by grouping investments for demand work execution and the purchase of spare power equipment. Details of specific programs are outlined in Table 8.

Table 8: Transmission Station Demand and Spares ($ Millions)

Ref #	Description	Test Years	
		2017	**2018**
S51	Demand Capital – Power Transformers	8.0	8.2
S52	Minor Component Demand Capital	4.7	4.7
S53	Operating Spare Transformer Purchases	8.2	8.3
	Other Demand and Spares Programs	4.5	4.7
	Total	**25.3**	**25.8**

Additional details for these investments are provided in the Investment Summary Documents S51 to S53 in Exhibit B1, Tab 3, Schedule 11.

4.2.4 Summary of Expenditures

The planned Transmission Station Demand and Spares expenditures for 2017 and 2018 are $25.3 million and $25.8 million respectively. The test year expenditures for the overall Transmission Station Demand and Spares program are based on historic spending required for emergency replacement of major power equipment and required equipment spare levels to effectively and prudently manage equipment failures. A reduction in this program will delay the replacement of failed equipment and will lead to maintaining a less than optimal spares inventory, resulting in increased risk exposure to reliability at both system stations and customer load delivery stations.

Ontario Energy Board (Board Staff) INTERROGATORY #069

Reference:
Exhibit B1/Tab3/Sch 2/ – Section 4.2.3: Investment Plan, pg. 19

"The purchase of operating spare transformers is in line with Hydro One's probabilistic approach to determine the number of spare requirements. The analysis considers performance trends and supply chain considerations of Hydro One's various power transformer types, and groups them into optimized spare cohorts to adequately cover the in-service population. The transmission operating spares requirement is intended to replenish inventory that is expected to be drawn down for future failures."

Interrogatory:
Please provide a table showing historic in-stock spares, annual draw-down and annual replenishment for 2012-2016, broken down into the following components:

- Autotransformers (>125 MVA);
- Large Transformers (>42MVA);
- Mid-size Transformers (15 to 42 MVA);
- 500 kV Breakers;
- 345 kV Breakers;
- 230 kV Breakers; and
- 115 kV Breakers.

Response:
The inventory of spare transformers and breakers specifying the draw-down and replenishment levels for each the years 2012 to 2016 is provided in the table below.

In Stock Spares as of Aug 18.	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	9	10	10	7	6
Large Transformers (>42MVA)	31	26	23	23	24
Mid-size Transformers (15 to 42 MVA)	19	18	13	16	16
500kV Breakers	3	3	4	4	5
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	17	18	20	19	18
115kV Breakers	4	6	9	14	13

Witness: Mike Penstone

Annual Draw-Down	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	1	0	1	1	2
Large Transformers (>42MVA)	0	3	2	3	1
Mid-size Transformers (15 to 42 MVA)	1	1	2	0	0
500kV Breakers	0	0	0	0	0
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	0	0	0	1	1
115kV Breakers	0	0	0	0	1

1

Annual Replenishment	**2012**	**2013**	**2014**	**2015**	**2016**
Autotransformers (>125MVA)	0	1	0	0	0
Large Transformers (>42MVA)	3	1	1	3	2
Mid-size Transformers (15 to 42 MVA)	0	1	0	1	0
500kV Breakers	0	0	1	0	1
345kV Breakers	N/A	N/A	N/A	N/A	N/A
230kV Breakers	8	1	2	0	0
115kV Breakers	0	2	3	5	0

2

TAB 4

Proposed Transmission Regulatory Scorecard - Hydro One Networks Inc.

Performance Outcomes	Performance Categories	Measures	Historical Years 2011	2012	2013	2014	2015	Trend
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	Satisfaction with Outage Planning Procedures (% Satisfied)	Note 1	78	Note 1	86	92	▲
		Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	13.8	10.8	12.8	11.8	Note 2	▲
	Customer Satisfaction	Overall Customer Satisfaction in Corporate Survey (% Satisfied)	85	76	81	77	85	-
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Recordable Incident Rate (# of recordable injuries/illnesses per 200,000 hours worked)	3.7	2.3	2.5	1.8	1.7	▲
	System Reliability	T-SAIFI-S (Ave. # Sustained Interruptions per Delivery Point)	0.60	0.61	0.57	0.60	0.59	-
		T-SAIFI-M (Ave. # Momentary Interruptions per Delivery Point)	0.60	0.65	0.69	0.48	0.50	▲
		T-SAIDI (Ave. Minutes of Interruptions per Delivery Point)	127.9	71.5	66.0	36.6	44.3	▲
		System Unavailability (%)	0.50	0.48	0.37	0.48	0.66	▼
		Unsupplied Energy (minutes)	21.6	14.0	20.9	12.2	11.8	▲
	Asset Management	*In-Service* Capital Additions (% of OEB approved plan)	95	75	90	106	85	▲
		CapEx as % of Budget	78	81	73	90	106	▲
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	9.8	8.6	7.6	8.4	9.0	▲
		Sustainment Capital per Gross Fixed Asset Value (%)	2.6	2.8	3.3	4.2	4.6	Note 3
		OM&A per Gross Fixed Asset Value (%)	3.4	3.0	2.7	2.7	2.9	▲
Public Policy Responsiveness Transmitters deliver on obligations mandated by government. (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board)	Connection of Renewable Generation	% on time completion of renewables connection impact assessments	100	100	100	100	100	-
	Market Regulatory Compliance	NERC/NPCC Reliability Standards Compliance						
		- Number of High Impact Violations (Note 4)	N/A	N/A	N/A	20	2	
		- Number of Medium/Low Impact Violations (Note 4)	N/A	N/A	N/A	5	10	
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met	N/A	N/A	N/A	100	100	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.24	0.29	0.80	0.69	0.13	
		Leverage: Total Debt (includes short-term & long-term debt) to Equity Ratio	1.27	1.22	1.10	1.16	1.39	
		Profitability: Regulatory Return on Equity — Deemed (included in rates) (%)	9.66	9.42	8.93	9.36	9.30	
		Profitability: Regulatory Return on Equity — Achieved (%)	10.95	12.41	13.22	13.12	10.93	

Note 1: Customer Satisfaction survey not done in 2011 and 2013.

Note 2: Results will be available in July 2016.

Note 3: In 2014 strategic decision made to increase sustainment capital.

Note 4: Results from 2011 to 2013 are excluded due to a lack of consistant data compared to 2014 and 2015.

Legend:
▲ up
▼ down
- flat

ATTACHMENT 1 - CUSTOMER DELIVERY POINT PERFORMANCE (CDPP) STANDARD

1. INTRODUCTION

The Transmission System Code (TSC) requires transmitters to develop performance standards at the customer delivery point ("CDPP")[1] level, consistent with system wide standards, that:

- reflect typical transmission system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- reflect historical performance at the customer delivery point level;
- establish acceptable bands of performance at the customer delivery point level for the transmission system configurations, geographic area, load, and capacity levels;
- establish triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, as well as the circumstances in which any such triggering event will not require the initiation of a technical or economic evaluation;
- establish the steps to be taken based on the results of any evaluation that has been so triggered, as well as the circumstances in which such steps need not be taken; and
- establish any circumstances in which the performance standards will not apply.

[1] A Delivery Point is defined as a point of connection between a transmitter's transmission facilities and a customer's facilities.

On May 3, 2002, Hydro One filed proposed Customer Delivery Point Performance Standards to meet the requirements of the TSC with the OEB for review and approval. Subsequently, on September 8, 2004, as a result of stakeholder comments received, Hydro One filed amendments to its original CDPP Standards submission. On July 25, 2005, the OEB issued its Decision and Order (RP-1999-0057/EB-2002-0424) which approved Hydro One's proposed CDPP Standards subject to a number of changes directed by the Board.

The approved CDPP Standards apply to all existing transmission load customers (including customers that have signed a connection cost recovery agreement prior to market opening). For new or expanding customer loads, the delivery point performance requirements will be specified and paid for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement.

2. DELIVERY POINT RELIABILITY STANDARDS

The approved CDPP Standards consist of two components;

- Group CDPP Standards that relate the reliability of supply to the size of load being served at the delivery point; and
- Individual CDPP Standards that maintain a customer's individual historical delivery point performance.

Triggers for each component are used to identify performance "outliers" to initiate technical and financial evaluations to determine the root cause of unreliability and remedial action required to improve reliability. The CDPP Standards and triggers for each component are summarized in Sections 2.1 and 2.2.

2.1 Performance Standards Based on Size of Load Being Served: Group CDPP Standards

The CDPP Standards and the associated triggers are based on the size of load being served. For this purpose, the load is the delivery point's total average station gross load[2] as measured in megawatts. The CDPP Standards vary with the size of the load in groups or bands of 0 to 15 MW, greater than 15 up to 40 MW, greater than 40 up to 80 MW and greater than 80 MW, as shown in Table 1.

Table 1: Customer Delivery Point Performance Standards Based on Load Size

Performance Measure	Customer Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		>15 - 40 MW		>40 - 80 MW		>80 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration (min/yr)	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

These CDPP Standards are based on historical 1991-2000 performance, as measured by the frequency and duration of all momentary and sustained interruptions[3] caused by

[2] Total Average Station Gross Load (MW) = (Total Energy Delivered to the Station (MWh) + Total Energy Generated at the Station Site (MWh)) / 8760 hours.

[3] Momentary interruption is any forced interruption to a delivery point lasting less than 1 minute and a sustained interruption is any interruption to a delivery point lasting 1 minute or longer. A delivery point is interrupted whenever its requisite supply is interrupted as a result of a forced outage of one or more Hydro One components causing load loss. Interruptions caused by Hydro One's customers are recorded but not charged against Hydro One's reliability performance for the customer initiating the interruption, but are charged against Hydro One's reliability performance for other interrupted customers.

2.1.2 Performance Standards to Maintain Historical Delivery Point Performance Individual CDPP Standards

In this component, the CDPP Standards are intended to maintain the reliability performance levels at each customer delivery point. This is done by identifying customer delivery points with deteriorating trends in reliability performance, irrespective of whether they are satisfactory performers under the Group CDPP Standards (Section 2.1). In order to identify customer delivery points with deteriorating trends in reliability performance, a performance baseline trigger for the frequency and duration of forced (momentary and sustained) interruptions is established for each delivery point based on that delivery point's historical 1991-2000 average performance, plus one standard deviation (the "historical baseline"). The historical baselines exclude outages resulting from extraordinary events that have had "excessive" impact on the transmission system and that, in Hydro One's assessment, strongly skew the historical trend of the measure (such as the 1998 ice storm, the 2003 blackout and the GTA Flood in 2013). Also, for delivery points that came into service after 1991, the in-service year is to be the first year of the 10-year period used to determine the performance baseline.

2.1.3 Criteria for Minimum Standard Performance to Identify Performance Outliers for Individual CDPP Standards

Delivery point performance that is worse than the historical baseline (for either frequency or duration) in two consecutive years is considered to be a performance outlier and a candidate for remedial action. In such cases, Hydro One will initiate technical and financial evaluations with affected customers to determine the root cause of the unreliability and the remedial measures required to restore the historical reliability of the delivery point's performance.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #005

Reference:
Exhibit B1/T1/S3/Attachment 1

Interrogatory:

a) Please explain the rationale for different customer delivery point performance standards based on load size.

b) Please explain why the standards are based on a 1991-2000 performance and not more recent data (e.g. 2006-2015).

c) Please provide the standards if based on the most recent 10 year data set available.

Response:

a) The Customer Delivery Point Performance (CDPP) Standard is based on load size in order to meet the Transmission System Code requirement to establish acceptable bands of performance at the customer delivery point level. Please refer to Exhibit B1, Tab 1, Schedule 3, Attachment 1, Page 1, Line 13.

b) The CDPP standard as approved by the OEB in RP-1999-0057/EB-2002-0424 is based on the historical 1991-2000 performance. There is no approval for a CDPP standard for other time periods.

c) The standard is based on the 1991-2000 performance.

Witness: Mike Penstone

Filed: 2016-08-31
EB-2016-0160
Exhibit I
Tab 12
Schedule 6
Page 1 of 1

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #006

Reference:
Exhibit B1/T1/S3/Attachment 1

Interrogatory:
a) Please clarify Table 1 by defining what is meant by "standard average performance" and "minimum standard of performance". Specifically, is the former the actual average performance (and if so for what period) and is the latter the 1991-2000 performance?

Response:
a) The "Standard (Average Performance)" is the average delivery point frequency of interruption, or average delivery point interruption duration for a given load group or band based on 1991-2000 performance.

The "Minimum Standard of Performance", for each of the four load size groups or bands, is used as a trigger by Hydro One. The trigger occurs when the three-year rolling average of the delivery point performance falls below the Minimum Standard of Performance for its load size group or band (referred to as a performance outlier or outlier) and is also based on 1991-2000 performance.

There is no approval for a CDPP standard for other time periods.

TAB 5

Ontario Energy Board (Board Staff) INTERROGATORY #060

Reference:

Exhibit B1/Tab2/Sch 7 – Section 6.2: Re-direction of Funds, pg. 17

"The re-direction of funds allows appropriate and prudent adjustments to be made to the work originally identified in the investment plan. As an example, the emergency restoration work needed to repair equipment failures or storm damage to a transmission line can be significant. Such events may necessitate the re-direction of funds and field resources from other investment areas."

Interrogatory:

a) What percentage of overall capital funds have been redirected from the investment plans in each year, from 2012 to 2015? Please identify the recipient and donor investment categories to and from which the funds were transferred, respectively, along with the rationale for the transfer.

b) For each project originally identified in the original investment plan but not executed as planned, please identify the rationale for re-directing funds to another project.

Response:

a) Between 2012 and 2015, redirection was not required to stay within the approved capital envelope as Hydro One underspent its capital budget.

b) Hydro One has project governance for variances that requires documentation and approval of material variances. The cost materiality threshold set by the governance structure is a forecasted cost increase of either: (a) more than 10% of currently approved funding and greater than $500,000; or (b) a variance greater than $2,000,000. There are also variances for scope changes or schedule changes, which are subject to the same governance structure, but with different thresholds. Below is a list of all projects, from 2012 to 2015 that met the materiality threshold in any combination of scope change, cost change or schedule change.

Project Name	Variance Type	Result of
Telematics	Schedule variance	Changing asset priorities based on new information
OMA Enterprise Content Management ECM	scope variance and Schedule variance	Changing customer needs and requirements

Witness: Mike Penstone

Project Name	Variance Type	Result of
Enhanced Asset Management Analytics (AA)	scope variance and cost increase	Changing asset priorities based on new information
IT Business Solutions Development SAP GIS Integration Project	Schedule variance and cost increase and scope variance	Changing asset priorities based on new information
customer Operations Mobile Phase 2B	Schedule variance and cost increase	Changing asset priorities based on new information
Domtar Green Transformation Generation Project (DC LINK)	Schedule variance and cost increase and scope variance	Changing external requirements
Terry Fox MTS Build New 230kV Line Tap	Schedule variance and cost increase	Changing customer needs and requirements
Lower Mattagami Generation Connections	Schedule variance and cost increase and scope variance	Undervalued estimate and scope increase
Leaside x Bridgman Transmission Expansion Project	Schedule variance and cost increase	Major unforeseen events
Lambton TS station Upgrade	Schedule variance and cost increase and scope variance	Changing customer needs and requirements
Port Arthur TS No 1 Install Series Reactors	Schedule variance and cost increase and scope variance	Unforeseen delay and cost increase in project component
H7L and H11L Mitigate 115kV Overvoltages Main TS Install 2 115kV Cct Breakers	Schedule variance and cost increase	Undervalued estimate
NetScaler Replacement Project	Schedule variance and cost increase and scope variance	Changing external requirements
H7L and H11L Mitigate 115kV Overvoltages	scope variance and cost increase	Undervalued estimate and scope increase
Uprate Short Circuit Capability of 15 115kV Breakers at Allanburg TS	Schedule variance and cost increase	Changing asset priorities based on new information
Manby TS Uprate 115 kV Station Short Circuit Capability	Schedule variance and cost increase	Undervalued estimate
Lambton TS Station Upgrade	Schedule variance and cost increase and scope variance	Changing asset priorities based on new information

Project Name	Variance Type	Result of
Basin TS 115kV Shunt Reactors and Arresters	Schedule variance and scope variance and cost increase	Undervalued estimate and scope increase, unforeseen delay in project component
Extreme Space Weather Readiness	Schedule variance and cost increase and scope variance	Changing customer needs and requirements
Crystal Falls SS Bulk	Schedule variance and cost increase and scope variance	Changing external requirements
D9H_D10S Line Refurbishment	Cost increase	Undervalued estimate
Kent TS DESN 1 Feeder M15 DG 274 Distance Limitation	Schedule variance and cost increase	Undervalued estimate
Orangeville TS Breaker Replacement	Schedule variance and cost increase	Undervalued estimate and scope increase
London Nelson TS EOL Replacement	Cost decrease and scope variance	Changing customer needs and requirements
Class EA Process Update	Cost decrease and schedule variance	Changing external requirements
Bridgman TS PCT Equipment Replacement	Scope variance and cost increase	Changing customer needs and requirements and changing external requirements
Hanmer TS Transmission Station Re Investment Project	Schedule variance and cost increase	Major unforeseen events
BSPS Replacement of End of Life Equipment Project	Schedule variance and cost increase and scope variance	Changing external requirements
Red Rock to Nipigon Hwy 11 17	Cost decrease and schedule variance	Scope decrease
2004 Monitoring Bruce GS add SER and Decommission (Bruce A and B RTUs)	Schedule variance and cost increase	Unforeseen delay and cost increase in project component
St Lawrence x Moses NYPA Tie Line Protection Replacement L33P and L34P	Schedule variance and cost increase and scope variance	Changing external requirements

UNDERTAKING – TCJ1.32

Undertaking

To provide the rationale behind what occurred, or the explanation of what occurred in those years.

Response

Explanation for Sustainment variances between Board Approved and Actuals from 2012 to 2015

The following provides examples of main projects or programs contributing to the variances in capital expenditures for Sustainment capital.

2012 Sustainment Capital Expenditures Variances

- Station Reinvestment: Delays associated with scope for Beck #1 SS reinvestment as the project underwent re-evaluation for potential lower cost alternatives, a one-time CCRA adjustment for historic work completed on Toronto Hydro's behalf and increased capital expenditures on work at Abitibi Canyon SS and Pinard TS resulted in a reduction of approximately $20M.
- Protection and Automation, Telecom: Delays associated with equipment selection for the Bruce Special Protection System replacement and revised requirements from the IESO, lack of resource availability due to other priority work, including the Bruce by Milton transmission lines, customer and outage coordination with international transmitters, and lower than estimated costs for DC signaling replacements in the GTA resulted in a $10M reduction.
- Transmission Underground Cables: Delayed project start of H2JK due to unexpected difficulties with obtaining land easements resulted in a $20M reduction.
- Increased capital expenditures across asset-centric program work at transmission stations and transmission line reinvestment contributed to a $25M increase (e.g. Claireville TS).

2013 Sustainment Capital Expenditures Variances

- Station Reinvestment: Timing of multi-year projects driven by customer commitments (e.g. Metal clad switchgear replacements), outage availability (e.g. Richview, Hanmer, Bruce A and Burlington Air Blast Circuit Breaker projects), resulted in a $25M reduction.
- Power Transformers: Timing of capital expenditures for the Claireville TS autotransformer replacement project as work was accelerated and largely completed within 2012 resulted in a $20M reduction.
- Protection and Automation, Telecom: Delays associated with equipment selection for the Bruce Special Protection System replacement, lack of resource availability due to other priority work, including the Bruce by Milton transmission lines, customer and outage coordination with international transmitters resulted in a $20M reduction.
- Cyber Security: Delays resulting from the delayed approval of NERC CIP Version 5 standards as investments were deferred until final approval of standards to ensure no assets or systems would be stranded or require additional investment due to the final requirements resulted in an $11M reduction.

2014 Sustainment Capital Expenditures Variances

- Power Transformers: The failure of the Trafalgar T15 autotransformer and advancement of transformer replacement at Gerrard TS resulted in a $25M increase.
- Protection and Automation and Telecom: Delays associated with equipment selection for the Bruce Special Protection System replacement, and customer and outage coordination with international transmitters contributed to an $8M reduction.
- Station Infrastructure: Increased spending to upgrade transmission station fire detection systems to required standards and upgrade station perimeter fencing to address security concerns resulted in an $11M increase.
- Cyber Security: Delays resulting from the delayed approval of NERC CIP Version 5 standards as investments were deferred until final approval of standards to ensure no assets or systems would be stranded or require additional investment due to the final requirements resulted in an $8M reduction.
- Transmission Overhead Lines: Increased wood pole replacements to address deteriorating condition of the fleet resulted in an $11M increase

- Transmission Lines Reinvestment: Increased capital costs associated with the C25H Line refurbishment resulted in a $5M increase.

2015 Sustainment Capital Expenditures Variances

- Station Investments: Increased costs associated with timing of the Bruce A 230 kV ABCB Breaker Replacement project expenditures and improved station investment execution approach enabled the delivery of emerging sustainment work at several notable transformer stations including Beach TS, Allanburg, Buchanan, Gerrard, and Hinchinbrooke to account for project delays at Gage, Elgin, and Beck contributed to an overall increase of about $90M.
- Transmission Lines Reinvestment and Overhead Lines: Increased investment to address asset needs on circuits, C25H, C22J/C24Z/C21J/C23Z, Q11S/Q12S, and D2L resulted in a $20M increase.
- Transmission Underground Cables: Delays associated with H2JK cable replacement resulted in a decrease of $10M.

Explanation for Development variances between Board Approved and Actuals from 2012 to 2015

The variances were mainly due to external factors (e.g. changes in government and OPA direction, customer cancellation or deferrals), project execution delays, and lower project costs. The following provides examples of main projects contributing to the variances in the capital expenditures for each particular year.

2012 Development Capital Expenditures Variances

- Nine projects to facilitate the Green Energy Act policy direction established in 2009 were subsequently cancelled and resulted in a $90 million reduction.
- The "Ancaster TS: Build New Transformer Station and Line Connection" project was cancelled at the customer's request and resulted in an $11 million reduction.
- The "Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate" was delayed due to outage cancellations and construction complexities. This resulted in a $15 million reduction.

2013 Development Capital Expenditures Variances

- Following the extension of Pickering NGS operating license to 2018, the "Clarington TS: Build new 500/230kV Station" project was deferred from 2015 to 2017 and resulted in a $65 million reduction.
- The "Installation of Static Var Compensator at Milton SS" project was cancelled by the OPA in August 2013 and resulted in a $30 million reduction.
- The "Nelson TS: Replace T1/T2 DESN with new DESN" project was cancelled at the customer's request and resulted in an $11 million reduction.

2014 Development Capital Expenditures Variances

- The "Installation of Static Var Compensator at Milton SS" project was cancelled by the OPA in August 2013 and also resulted in a $40 million reduction in 2014.
- The "Reconductor the Lambton TS to Longwood TS 230 kV Circuits" project was completed $13 million lower than forecasted.
- The "Midtown Transmission Reinforcement Plan" was delayed due to a tunnel shaft shoring failure and difficulty in obtaining outages. This resulted in a $10 million reduction.

2015 Development Capital Expenditures Variances

- The "Clarington TS: Build new 500/230kV Station" project was delayed due to difficulties obtaining the Environmental Assessment approval and resulted in a $13 million reduction.
- The KWCG Regional Infrastructure Plan determined that the need for the "Preston TS Transformation" project can be deferred to beyond 2025. This resulted in a $10 million reduction.
- Delays in obtaining major approvals for the "Supply to Essex County Transmission Reinforcement" project resulted in a $9 million reduction.
- The "Guelph Area Transmission Reinforcement" project cost is lower than forecast and resulted in a $6 million reduction.
- The scope for the "Seaton TS: Build New 230-28 kV Transformation Station" project has changed as the customer is now building their own transformer station. The project scope now only involves a connection line facility. This has resulted in a $6 million reduction.

TAB 6

School Energy Coalition (SEC) INTERROGATORY #024

Reference:
B1/2/7

Interrogatory:
Please explain where rate impact is considered within the investment planning process?

Response:
Rate impact is considered throughout the investment planning process. At the start, customer consultation feedback and senior executive expectations are incorporated into a guideline that is communicated to staff and influences investment prioritization. As investment planning progresses, the effect of investment levels on rates is continually reviewed to compare the extent of required investments and their effect on rates with expectations outlined at the beginning of the process.

Witness: Mike Penstone

Ontario Energy Board (Board Staff) INTERROGATORY #067

Reference:

Exhibit B1/Tab3/Sch 2/ – Section 4.1.3: Summary of Expenditures, pg. 16

"In general, Hydro One's fleet of stations has deteriorated to the point of requiring significant investment to maintain and operate a safe and reliable transmission system."

Interrogatory:

a) Please explain if the situation described above has arisen unexpectedly, or if this situation was expected, please provide the justification for allowing the situation to develop.

b) Did Hydro One conduct cost-benefit analysis in past years to evaluate the long-term rate impact of deferring required Sustaining Capital Investments versus increased operational costs? If yes, please provide documentation of this analysis.

Response:

a) No, this situation has not arisen unexpectedly. The expected service life profile of Hydro One's asset base (reference Exhibit B1, Tab 2, Schedule 4, Section 6) clearly shows that a sizable portion of the asset base is currently operating beyond their normal expected service lives; specifically: 28% of transformers, 9% of breakers and 19% of conductors. Over the next ten years, this will significantly increase to 58% of transformers, 40% of breakers and 42% of conductors operating beyond their normal expected service lives with a looming bow wave of assets reaching their ESL starting in 2030. As such, significant sustainment capital investment will be needed between 2016 and 2030 to address the assets that are at end of life in order to maintain and operate a safe and reliable transmission system. Exhibit B1, Tab 2 Schedule 4, Section 6, outlines the justification for allowing this situation to develop.

b) No, Hydro One has not carried out a cost benefit analysis in past years to evaluate the long term rate impact of deferring required Sustaining capital investments. Hydro One always balances the needs of the assets with available resources.

Witness: Mike Penstone