EB-2019-0082

IN THE MATTER OF the Ontario Energy Board Act, 1998 ("Act");

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an order or orders made pursuant to section 78 of the Act approving rates for the transmission of electricity.

CME Compendium – Witness Panel #1

October 21, 2019

Defective porcelain insulators manufactured by Canadian Ohio Brass ("COB") and Canadian Porcelain ("CP") are identified as high risk and have been targeted for replacement. Hydro One will invest $341 million over the TSP period. In each of 2020 and 2021, it will target 3,700 circuit structures that have defective insulators and that are situated in publicly accessible areas. Beginning in 2022, Hydro One will target 3,450 such circuit structures per year that are not situated in publicly accessible areas (ISD SR-25). This investment is key to preventing insulator failures, which can result in outages and energized conductors falling to the ground (thereby posing significant safety hazards and reliability concerns).

Hydro One will invest $50 million over the five-year plan to support power restoration following transmission line component failures and to replace or repair line components that are likely to fail as identified through line patrols or asset assessment (see ISD SR-26). Given the demand and reactionary nature of this program, the level of investment is in line with historic levels.

Lastly, Hydro One will invest $124 million over the five-year plan to replace 7.2 km of high voltage underground cable due to poor cable performance, condition, and component obsolescence (see ISD SR-27).

Renewal drivers relating to overhead conductors and line insulators are more specifically discussed below.

3.1.1.2.1 Overhead Line Conductors

The conductor of an overhead transmission line transports electricity between system nodes. As such, overhead conductors are the single largest and most vulnerable component of the transmission line system. Lines have been a major contributor to customer delivery point interruptions over the past 10 years, representing 45% of these equipment-caused events. Specifically, given the lack of redundancy, single circuit supplies, which include radial connections, are more likely to result in a customer interruption due to a component failure or weather event. Currently, about 5% of the overhead conductors have reached or exceeded their ESL of 90 years. Without the proposed level of investment, the percentage of conductors exceeding ESL would increase to 13% by 2024.

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.

3.1.1.2.2 Line Insulators

Line insulators are an integral component of the transmission system. They mechanically support and electrically insulate the conductor from the pole or tower structure, and provide sufficient dielectric strength to prevent short circuits to ground. There are approximately 437,000 insulator strings in Hydro One's overhead transmission network.

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

2.2.2 (5.3.2 B, C, D) ASSET COMPONENT INFORMATION – TRANSMISSION LINES

Transmission lines are used to transmit electric power, via network and radial circuits, to either direct transmission customers or to transformation points for distribution to retail customers. Transmission line major components include overhead conductors, underground cables, structures, foundations, insulators, and shieldwires.

2.2.2.1 OVERHEAD CONDUCTORS

Asset Description / Purpose

The conductor of an overhead transmission line is the asset responsible for transporting electricity between system nodes. Over 99% of Hydro One's transmission system is comprised of overhead power lines as opposed to underground cables. The conductor is the single largest and most vulnerable component of the transmission line system. Close to 98% of Hydro One's overhead conductor fleet utilises aluminum conductor steel reinforced ("ACSR") conductor types; with copper, aluminum and aluminum conductor steel supported ("ACSS") types making up the balance.

Asset Condition / Demographics

Demographics

Following a recent analytical study conducted the Electric Power Research Institute ("EPRI") Hydro One has changed ESL for its ACSR conductor type from 70 years to 90 years. Further details on this study are available in Section 1.4. The actual life span of each conductor can vary between 50 and 120 years because numerous uncontrollable variables affect conductor deterioration, including manufacturing material quality, location, orientation, local atmospheric pollution levels, weather cycles and stringing tension. Presently, Hydro One's conductor fleet has an average age of 55 years.

Currently, about 5% of the overhead conductor fleet has reached or exceeded its ESL of 90 years. Table 17 below summarizes the demographic profile of the overhead conductor fleet. Without any further replacements, the percentage of conductors exceeding ESL will increase to about 13% by 2024.

Table 17 - Overhead Conductor Demographics

Conductor Type	Circuit km in Service	Average Age (Years)	ESL (Years)	Beyond ESL	Beyond ESL 2024	Beyond ESL 2029
ACSR	28,437	54	90	876	3,125	3,988
Copper	512	97	70	512	512	512
Aluminum	21	89	100	0	15	15
ACSS	137	26	N/A*	0	0	0
Total	**29,107**	**55**		**1,389**	**3,653**	**4,516**

** Relatively new conductor type to Hydro One, limited installation, ESL to be established*

Condition

Hydro One operates a condition assessment program that identifies conductors that are beyond 50 years as candidates for assessment to determine the condition through testing. Based on Hydro One's operating experience, conductors below 50 years of age are considered low risk and have a small likelihood of being in a deteriorated condition.

By the end of 2024, about 13% or 3,653 circuit km of the conductor fleet will reach or exceed its ESL. Condition assessment results indicate that about 13% or 3,680 circuit km of the conductor fleet is known to be in high risk conditions, as shown in Figure 18 below. This includes ACSR conductors verified to be in poor condition through testing, and copper conductors, many of which suffer from damage caused by lightning strikes, mechanical strength loss and can no longer be repaired due to obsolete repair components.

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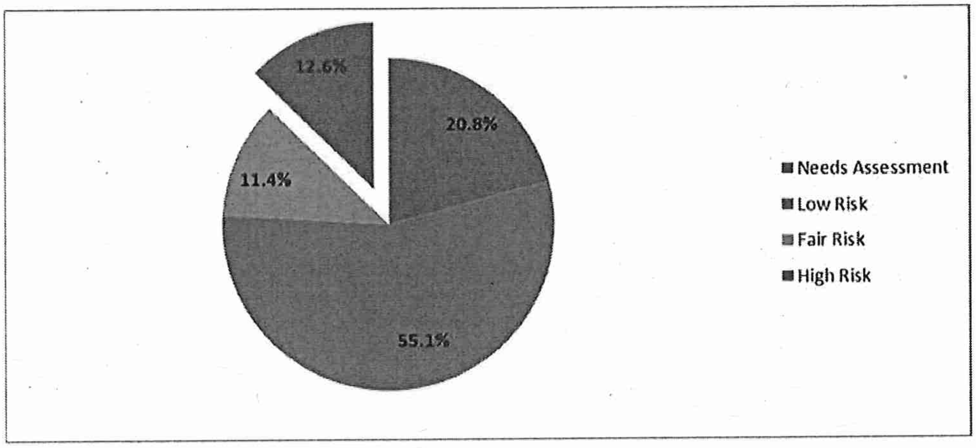

Figure 18 - Distribution of Overhead Conductor Condition

Performance

Failure of an overhead conductor can have severe consequences both in terms of reliability and safety. 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 with the exception of abnormalities in 2009 and 2015, as outlined in Figure 19 and Figure 20. In 2009, circuits B10H/B20H required an extended forced outage to accommodate an emergency conductor replacement.[8] In 2015, an extended forced outage was required to replace twelve misaligned conductor sleeves along circuit A6R.

Hydro One has made some progress in addressing the condition assessment backlog for conductors. Relative to the EB-2016-0160 filing, the percentage of conductors requiring assessment has decreased from 31% to 21%. While many of the circuits assessed were found to be in low risk condition, the proportion of high risk conductors increased from 9% to 13% as confirmed by testing. As more conductors deteriorate and fall into the high-risk category, the risk of failure is also expected to increase, which is likely to

[8] B10H/B20H circuits are self-damping conductors that required replacement due to mechanical failures (rather than due to age-related deterioration).

translate into more frequent conductor-related outages and/or prolonged outage durations (i.e., where the line is a radial supply). While age is not the determining factor for conductor replacement decisions, it is nevertheless a useful proxy in relation to asset condition and associated risk of failure, which are confirmed through actual assessment and testing. Given the drastic increase in conductors reaching or exceeding their ESL from now to 2024 (see Table 17 above), coupled with testing results to date showing an increase in the proportion of high risk conductors, Hydro One has to proactively replace conductors in a well-planned and paced manner so as to ensure the ongoing safe and reliable operations of Ontario's BES. As illustrated in Figure 19 and Figure 20, there have been significant spikes in outage frequency and duration in certain years, which impact the overall trend line and simply cannot be predicted with any degree of accuracy. In light of the above considerations, despite the overall downward trend of forced outage frequency and duration relating to overhead conductors, it would not be prudent to wait until noticeable reliability degradations materialize before undertaking the required investments.

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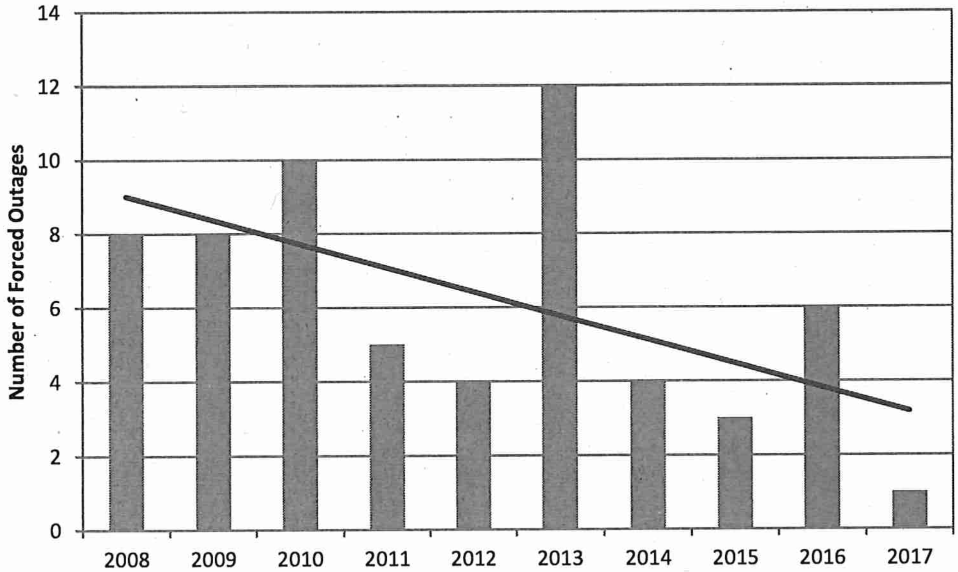

Figure 19 - Overhead Conductor Forced Outage Frequency

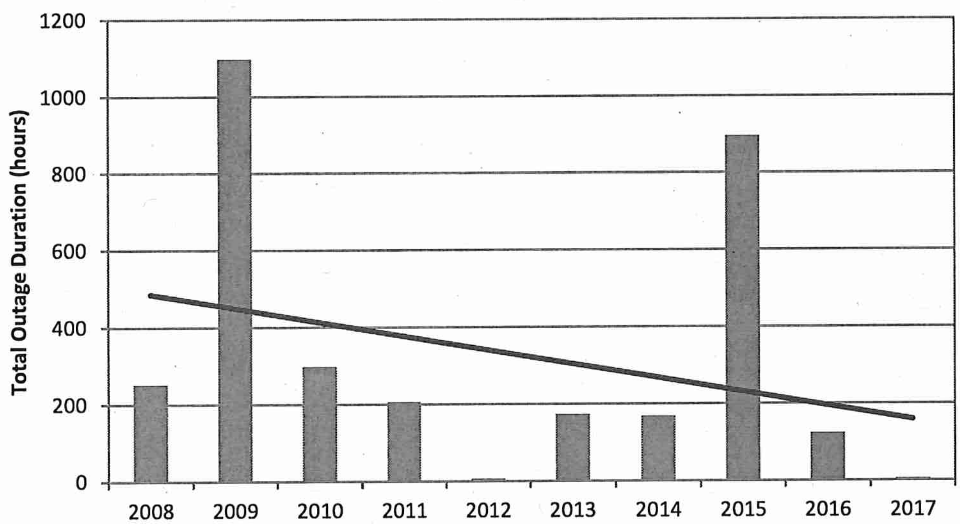

Figure 20 - Overhead Conductor Forced Outage Duration

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Future Outlook / Need

The number of conductors beyond ESL is increasing, despite a planned increased level of replacements when compared to historical levels. If this issue is not addressed in a proactive and timely manner, system and customer reliability and safety will be placed at risk. Consequently, an increase in planned replacements is required to maintain acceptable fleet condition and performance and to avoid a drastic spike in investments that would otherwise be required in the future as a result of deferred replacements. However, not all conductors beyond ESL require replacement, as many conductors beyond ESL have been found to be in good or fair condition. Hydro One has increased the condition assessment program in order to accurately assess the conductor fleet that has yet to be reviewed (21% of the fleet) and thereby effectively identify conductors requiring replacement.

Hydro One is currently evaluating the C-corr technology developed by EPRI. This device is a non-contact tool that can be operated from the ground and can be used to assess the condition of conductors with steel cores by analyzing the discolouration signatures between the aluminum layers. C-corr technology can potentially reduce the cost of conductor condition assessment if proven to be accurate. Hydro One will re-evaluate implementation of this technology as test results become available to prove its reliability and cost-benefit values.

2.2.2.2 UNDERGROUND CABLES

Asset Description / Purpose

Underground transmission line cable systems are typically used to link portions of the overhead network or connect substations. They are mainly used in urban areas where it is either impossible or extremely difficult to build overhead transmission lines due to urban density, legal, environmental or safety issues.

SR-19 Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures

Start Date:	Q4 2015	**Priority:**	High
In-Service Date:	Q4 2025	**3 Year Test Period Cost ($M):**	298.4
Trigger(s):	Strategic, System Renewal		
Outcomes:	Improve system reliability, minimize customer outages, reduce maintenance costs associated with the EOL assets, realize cost savings and efficiencies as a result of bundling needed work within this investment		

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.

These assets pose safety and system reliability risks should they fail. In addition, copper conductors are the oldest type of overhead conductors in the Hydro One transmission system and are now obsolete. Hydro One is no longer able to mend some broken copper conductors due to this obsolescence. These Line Refurbishment Projects aim to remove and replace these deteriorated EOL conductors, or refurbish high risk structures to sustain safe and reliable delivery of electricity. 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. The projected cost of these Projects is estimated to be $298.4 million over the 2020-2022 test period.

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C. EXPENDITURE PLAN

As discussed above, Line Refurbishment Projects are needed to replace/refurbish the EOL ACSR conductors, obsolete copper conductors and line sections with deteriorated structures, in order to mitigate the risk to safety and reliability that would result from their failure. Hydro One planned these projects in a way that strives to complete it as effectively and efficiently as possible to minimize the cost of performing this sustainment need.

Table 6 summarizes historical and projected spending on the aggregate. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 6 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	175.1	88.7	131.7	102.3	55.1	81.8	0.0	634.7
Less Removals	17.0	6.9	9.6	7.8	4.1	5.9	0.0	51.3
Gross Investment Cost	**158.1**	**81.8**	**122.1**	**94.5**	**51.0**	**75.9**	**0.0**	**583.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**158.1**	**81.8**	**122.1**	**94.5**	**51.0**	**75.9**	**0.0**	**583.4**

[1] Includes overhead at current rates.

Table 7 presents test year costs for individual projects and presents the total cost for EOL ACSR, obsolete copper and deteriorated structure driven line refurbishment projects. The total cost includes costs incurred in previous years and forecasted beyond 2024, where applicable.

SR-20 Transmission Line Refurbishment - Near End of Life ACSR Conductor

Start Date:	Q4 2016	**Priority:**	Medium
In-Service Date:	Q4 2026	**3 Year Test Period Cost ($M):**	237.3
Trigger(s): Strategic, System Renewal			
Outcomes: Improve system reliability, minimize customer outages, reduce maintenance costs associated with the High Risk assets, realize cost savings and efficiencies as a result of bundling needed work within this investment			

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. This conclusion is supported through mathematical modelling completed by a third party expert, Electric Power Research Institute ("EPRI").

EPRI developed a conductor hazard curve and applied it to forecast the amount in kilometres of ACSR overhead transmission conductor expected to be in high risk condition (i.e. EOL or near EOL). The EPRI report forecasts that 3,920 circuit km of the ACSR conductor fleet will be at EOL or near EOL condition by 2024.[1] This forecast of ACSR conductor condition aligns with the fact that by the end of 2024, about 13% or 3,653 circuit km of the overall conductor fleet will reach or exceed their ESL without further replacements.

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[1] TSP Section 1.4 Attachment 4 - Derivation of Overhead Conductor Hazard Function, section 5-3, p 93.

for this set of Projects. The "Previous Years" costs are the direct project costs for projects noted above that have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024. Table 3 summarizes historical and projected spending on the aggregate.

Table 3 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	15.0	67.6	68.9	121.4	128.0	149.7	143.2	693.9
Less Removals	1.2	5.4	5.5	9.7	10.2	12.0	11.5	55.5
Gross Investment Cost	**13.8**	**62.2**	**63.4**	**111.7**	**117.8**	**137.7**	**131.8**	**638.4**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**13.8**	**62.2**	**63.4**	**111.7**	**117.8**	**137.7**	**131.8**	**638.4**

[1] *Includes overhead at current rates.*

Table 4 below presents the projected costs on an individual project basis. It also provides the total cost, which includes costs incurred in previous years and forecasted beyond 2024, where applicable, for each individual project along with the proposed in-service date.

Schedule 2, Attachment 1), and some customers criticized Hydro One for not spending sufficiently on sustainment capital historically (Exhibit B1, Tab 2, Schedule 2, Attachment 1). This feedback is also consistent with the results of Hydro One's customer survey, in which customers indicated concern with reliability and power quality (Exhibit B1, Tab 2, Schedule 2).

Hydro One also sought feedback from customers on a range of investment levels, represented by three scenarios that translated into different rate impacts and changes in reliability risk. Customers generally indicated a desire for maintained or reduced reliability risk, consistent with a higher level of capital investment.

Hydro One considered the feedback obtained during customer consultations in its investment plan.

6. SUSTAINMENT FORECAST AND EXTERNAL CONSTRAINTS

In developing its five year transmission system plan, Hydro One considered several key internal and external execution related factors while developing the level and the pacing of investments:

- Work execution capabilities;
- Expected future asset replacement needs in 2022 and beyond; and
- Outage constraints related to planned investments affecting generation on the system.

Hydro One has made significant investments in development capital from 2009 to 2012 to comply with government policy related to renewable energy and to increase system capacity to facilitate changes in the generation mix, including the Bruce to Milton 500 kV double circuit line, which was completed in 2011. While this work was necessary to further the energy objectives of the Province, sustainment investments were deferred.

The ESL profile of Hydro One's asset base suggests that significant sustainment capital will be needed between 2016 and 2030 in order to prevent an increase in reliability risk. Figures 2, 3, and 4 below show the demographic distribution of transformers, breakers and conductors currently in service on the transmission system. A sizable portion of each critical asset class is operating beyond expected service life, contributing to an increase in reliability risk. Specifically, 28% of transformers, 9% of breakers and 19% of conductors are currently operating beyond their normal expected service lives.

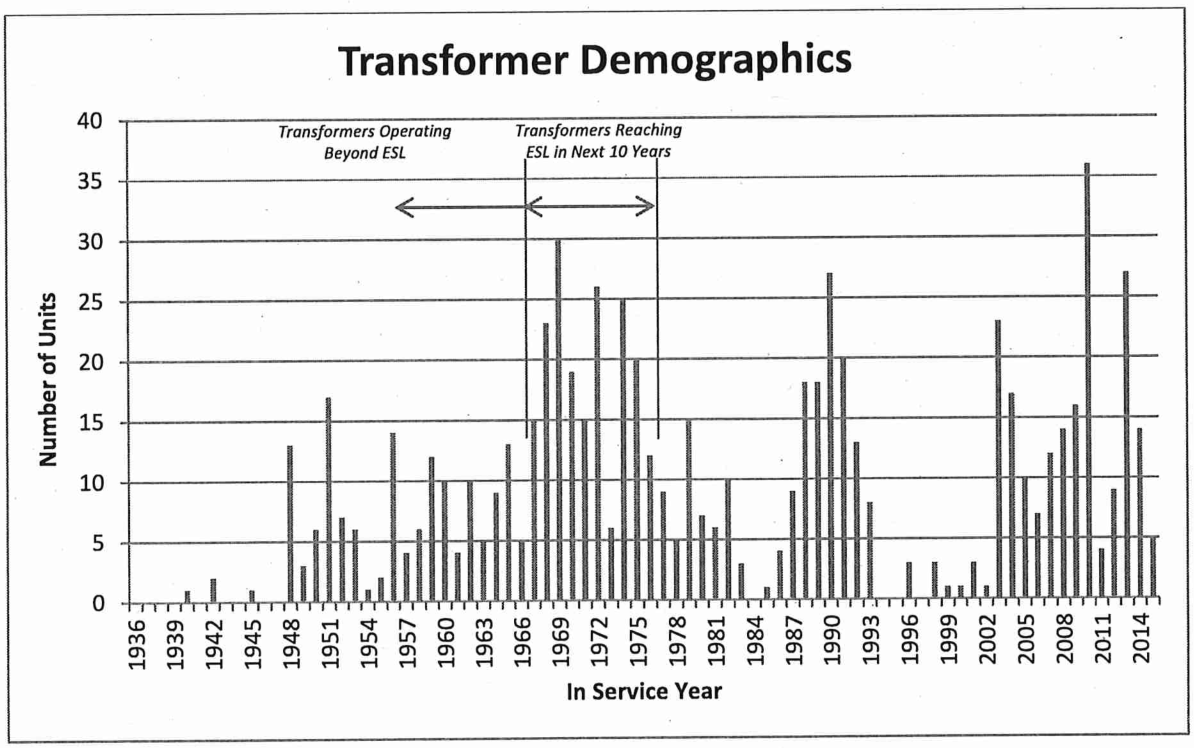

Figure 2: Transformer Demographic Distribution

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overview of the main factors driving the investments in each of these categories is set out below.

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.

The TSP also delivers an increased emphasis on line renewal investments at a cost of approximately $2.0 billion to refurbish and replace end of life transmission lines, underground cables, insulators, and wood poles while continuing with tower coating of steel structures to extend their useful life, but at a reduced pacing consistent with prior direction from the OEB. While the planned rate of refurbishment does not keep pace with the overhead lines demographics, the risk is managed through the use of detailed conductor assessments to identify poor condition conductors, informing the line refurbishment program. Lines are candidates for conductor condition assessment starting at 50 years of age.

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

impact of unplanned failures across all transformer types. Validation of the Hydro One transformer spare strategy and model is discussed in Section 1.4.

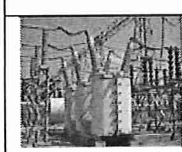
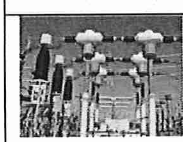
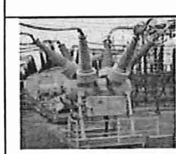
2.2.1.2 CIRCUIT BREAKERS

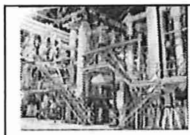
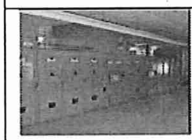
Asset Description / Purpose

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, circuit breakers are capable of operating rapidly to interrupt high current thereby minimizing its effect on the rest of the power system.

Circuit breakers use a variety of interrupting mediums that have evolved over time. Hydro One's circuit breaker fleet has been summarized in Table 5 below according to the interrupting medium used, along with the production and environmental status.

Table 5 – Breaker Fleet Description

	Breaker Type	Interrupting Medium	Production Status	Safety and Environmental Concerns
	Oil Circuit Breakers ("OCB")	Oil	Legacy, Out of Production	Oil spill, PCB* content
	Air Blast Circuit Breaker ("ABCB")	Air	Legacy, Out of Production	Noise
	Sulfur Hexafluoride ("SF6") Breaker	SF6	Commercially available	SF6 is a greenhouse gas

	Gas Insulated Switchgear ("GIS")	SF6, Vacuum**	Commercially available	SF6 is a greenhouse gas
	Metalclad Switchgear	SF6, Vacuum, Air, Air Magnetic	Commercially available	Arc flash hazard
	Vacuum Breaker	Vacuum	Commercially available	None

** Polychlorinated Biphenyls ("PCB")*
*** MVGIS uses vacuum interrupters as interrupting medium and SF6 acts as insulating medium*

Asset Condition / Demographics

Demographics

Hydro One has 4,774 High Voltage ("HV") and Medium Voltage ("MV") breakers. The breaker fleet includes 549 breakers that are currently beyond their ESL. Projections for 2024 and 2029 (assuming no replacements or failures) are summarized in Table 6 below. A large number of oil, air blast and metalclad breakers have reached their ESL with an increasing number of breakers forecasted to reach ESL within the next decade. As breakers approach their ESL, vendors typically communicate their transition to limited support or complete obsolescence of aged product lines. It is important to proactively manage and mitigate this impending wave of assets approaching ESL in order to avoid difficulties in obtaining spare parts to sustain breakers that vendors no longer support.

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Table 6 - Summary of the ESL of Hydro One's Breakers*

Type of Breaker	HV 115-500kV	MV 44-12.5kV	Total	Avg. Age	ESL (Years)	Currently Beyond ESL	Beyond ESL **2024	Beyond ESL **2029	% of Fleet Currently Beyond ESL (2018)
Oil Breaker	377	1,242	1,600	42.2	55	151	499	773	9.40%
Air Blast Breakers	133	24	157	46.5	40	129	157	157	82.20%
SF6 Breakers	783	1,074	1,857	14.2	40	10	17	142	0.50%
GIS Breakers	276	88	364	23.9	40	108	147	161	29.70%
Metalclad Breakers	0	767	767	27.8	40	151	268	341	20%
Vacuum Breakers	0	29	29	15.4	40	-	-	3	0.00%
Total	**1,569**	**3,224**	**4,774**	**27.6**		**549**	**1088**	**1766**	**11.50%**

* data current as of Dec 30, 2018
** as of December 31 of that year assuming no failures or replacements

Condition

Breaker condition is monitored through information gathered during preventive inspection and maintenance activities. Breaker failures can severely impact system stability, other connected equipment and employee and public safety. Consequently, it is important to ensure that the current carrying components are in good shape, the mechanical and control systems are operating within specification and that the insulating medium has not been compromised.

As breakers age their O-rings and gaskets slowly degrade, thereby causing leaks, which will result in a lower pressure and a path for moisture ingress. Over time, this condition can result in lower dielectric strength in the breaker and potential for internal flashover, which could lead to an explosive failure of the breaker. Where feasible based on parts availability, cost and projected future reliability, breakers with leaks are repaired as part of ongoing maintenance activities.

As of December 2018, the breaker fleet's condition shows that 9% are rated at a high or very high risk, as illustrated in Figure 8 below.

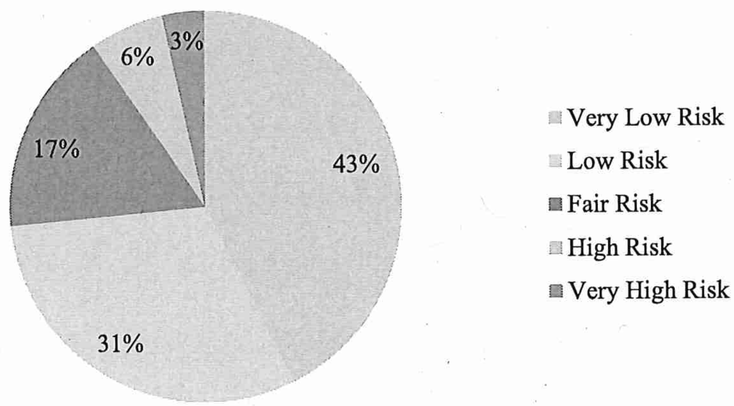

Figure 8 - Overall Breaker Fleet Condition

Performance

Circuit breaker performance is measured by assessing the number of forced outages. A "forced outage" is the automatic or forced manual removal of high voltage breakers caused directly by the breaker itself or terminal equipment directly adjacent to the breaker. Typical breaker failure modes have included control component issues, air leaks, gas leaks, operating mechanism issues, moisture content problems and auxiliary equipment malfunctions.

The number and duration of forced outages due to circuit breakers have increased over the past decade with a flattening trend in the last five years, as illustrated in Figure 9 and Figure 10 below. This overall increase is primarily attributed to the number of ABCB-related forced outages.

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The significant increase in the 2013 forced outage frequency was predominantly due to the increase in ABCB air system control component failures. The CGE AT breaker population experienced the greatest number of air system component failures. In some cases, such failures led to breaker fail protection operations that forced the tripping/opening of adjacent breakers. This can cause interruptions to circuits and busses, which could give rise to customer outages. These performance issues have also resulted in multiple instances where generators were forced offline.

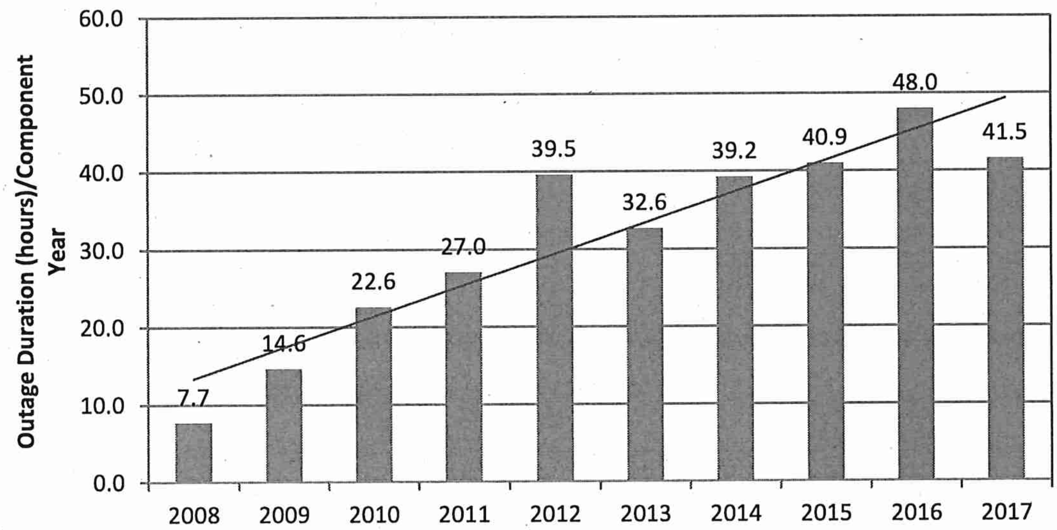

Figure 9 - Circuit Breaker Forced Outage Duration

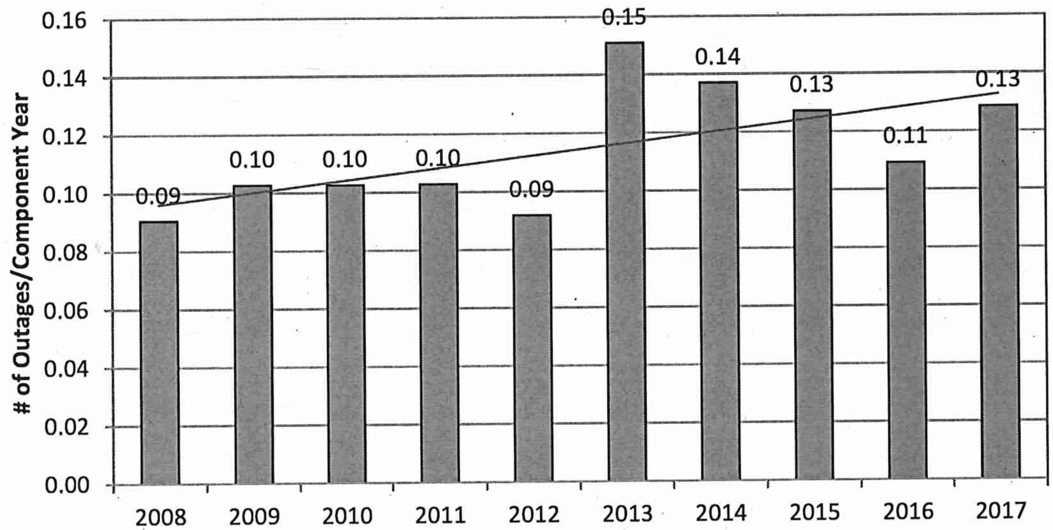

Figure 10 - Circuit Breaker Forced Outage Frequency

Forced outage frequency by breaker type in Figure 11 below illustrates the doubling of ABCB related outages over the last 10 years. This increasing trend is due to known air system issues caused by deteriorated O-rings, valves and problems with control components.

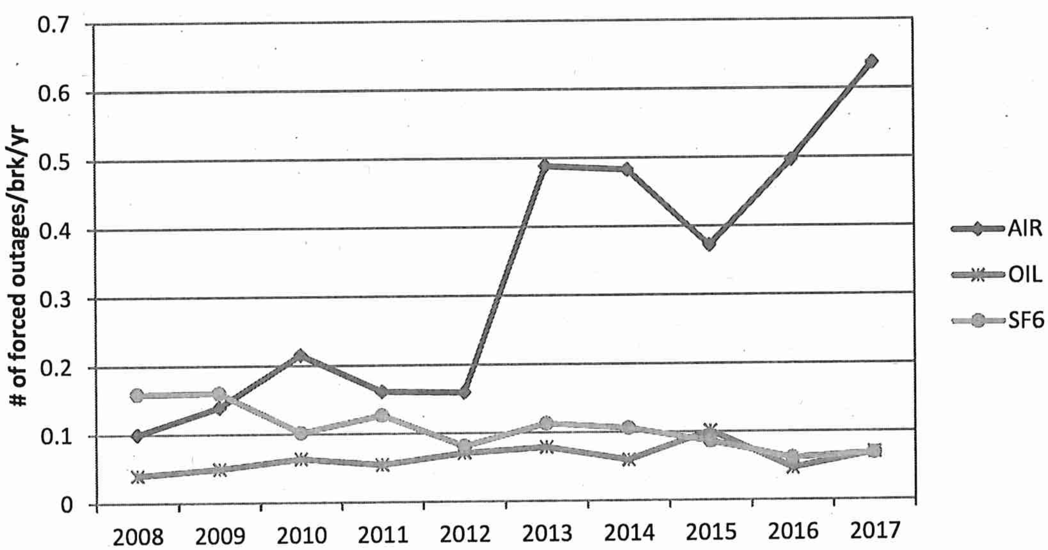

Figure 11 - Summary of Forced Outages by Breaker Type

Continued renewal of the fleet will be required to manage risks to system and customer reliability as a result of the long-term demographic pressures, as well as the more acute issues associated with air blast and metalclad circuit breakers.

Performance

As displayed in Figures 8 and 9, the number of forced outages due to circuit breakers and the duration of those outages both increased beginning in 2013. This was primarily the result of increased outages among the Air Blast Circuit Breakers (ABCB) compared to previous years.

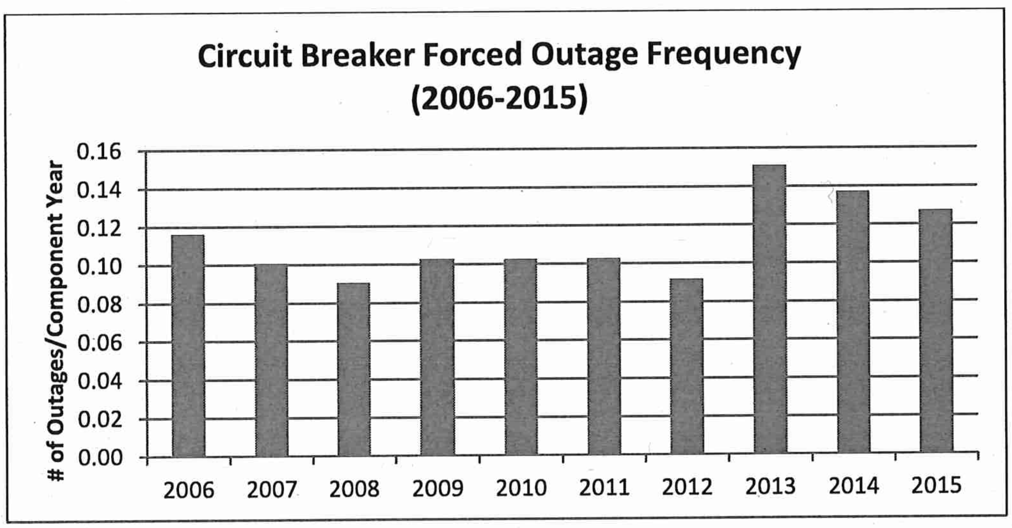

Figure 8: Forced Outages Frequency of Circuit Breakers

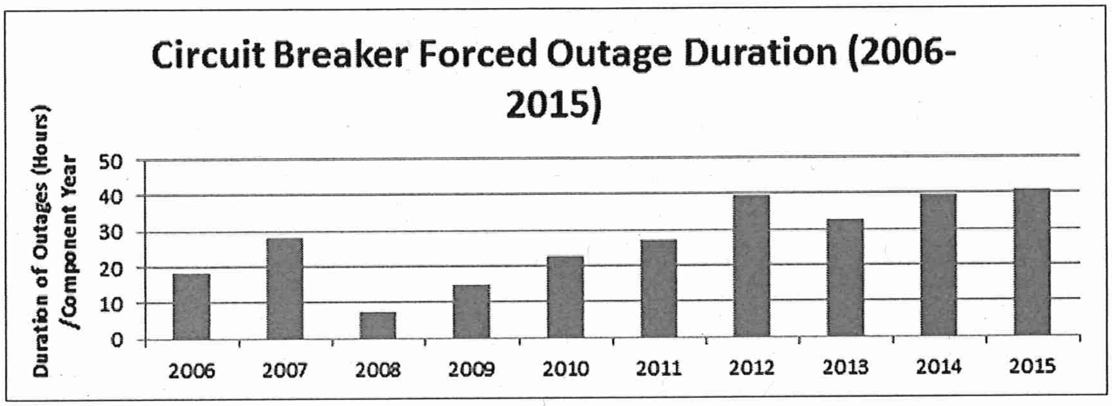

Figure 9: Forced Outage Duration Caused by Circuit Breakers

In 2014 and 2015 the number of outages has been declining modestly from 2013 as ABCBs have been replaced throughout the system. This trend is notable in Figure 10, where the performance data for the different breakers in Hydro One system is depicted. Oil and SF6 breakers have steady trend whereas ABCBs have a significant increase.

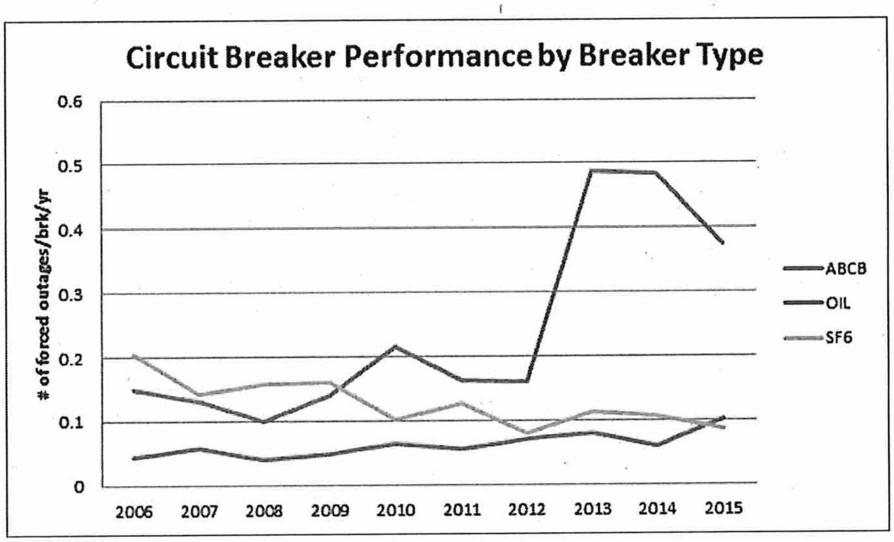

Figure 10: Forced Outage Frequency of Circuit Breaker by Type

Condition

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3.2.4.1 Operating Spare Transformers Requirement Assessment

This study found that the results of Hydro One's Markov model analysis (used to determine the appropriate number of spare transformers), aligns with the independent and alternative analysis from the third-party expert, Electric Power Research Institute ("EPRI"). Hydro One continues to take steps to achieve and maintain the required quantity of operating spare transformers to ensure reliability and improve cost efficiency.

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. This pacing of transformer replacement has been reflected in the following ISDs: SR-02 (Station Reinvestment Projects), SR-03 (Bulk Station Transformer Replacement Projects), SR-05 (Load Station Transformer Replacement Projects), and SR-08 (John Transformer Station Reinvestment).

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. However, older circuit breakers are being replaced at a quicker rate than expected. The reason for faster paced replacement is due to replacement criteria that are not included in the EPRI report as explained below.

Hydro One plans to address 638 breakers over the planning period. This includes the removal of 49 breakers as a result of station decommissioning and reconfiguration as well as the additional installation of 15 breakers resulting from customer requests to increase operational flexibility in the Toronto area. As per the EPRI analysis, there is a 90% probability that Hydro One will need to replace 491 breakers or fewer. However, Hydro One's volume of replacement over the plan period is higher primarily due to obsolescence concerns, safety concerns (e.g. insufficient arc resistance), PCB mitigation, and integrated investments which are not reflected in the EPRI analysis.

The EPRI analysis is derived from asset retirement data from 1981 to 2017. The analysis does not reflect the necessary replacement of 95 ABCBs over the planning period due to worsening reliability, as Hydro One has operated its fleet longer than industry peers. Similarly, the historical mid-life refurbishment of oil breakers from 1950 to 2007 has enabled Hydro One to operate approximately 300 currently in-service breakers for a longer period prior to retirement. Based on how the calculations were performed, this skews the predicted replacement rate. PCB mitigation also contributes to the increased rate of replacement in order to meet federally legislated deadlines. Out of the 247 oil circuit breakers identified for replacement over the planning period, 69 (28%) have measured above the acceptable level of 45 ppm for PCBs. Due to increased obsolescence concerns and the lack of, or reduction of, vendor support with respect to oil, metalclad, and vacuum breakers, the capital plan paces breaker replacements to mitigate reliability impact. Where breakers that are not end of life are removed from service because it is part of an integrated investment (e.g., due to the replacement and relocation of a switchyard), these breakers are placed into spares to support the remaining fleet. Oil circuit breakers can be salvaged for parts to support the remaining fleet, while complete SF6 breakers are placed into the spare equipment pool to support demand replacements.

This pacing of circuit breaker replacement has been reflected in the following ISDs: SR-02 *Station Reinvestment Projects*, SR-04 *Bulk Station Switchgear and Ancillary Equipment Replacement Projects*, SR-06 *Load Station Switchgear and Ancillary Equipment Replacement Projects*, and SR-08 *John Transformer Station Reinvestment.*

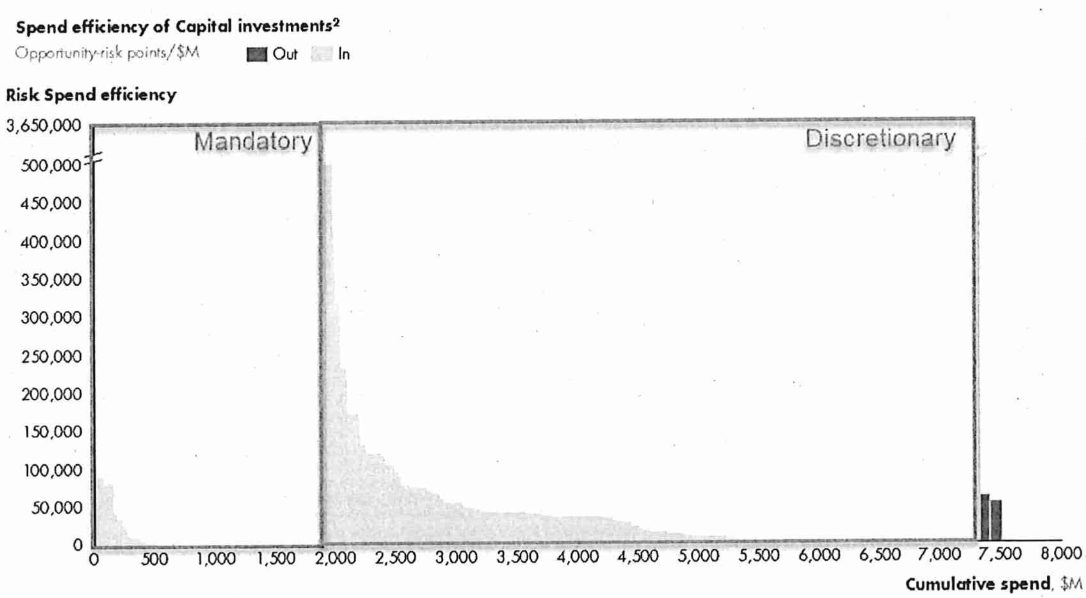
UNDERTAKING - JT 1.12

Reference:
I-07-SEC-032, part a)

Undertaking:
To provide data clarifying costs and risk score (reference SEC IR 32).

Response:
The table below has been structured in a manner consistent with the pre-filed evidence to allow for a meaningful comparison. Investments have been categorized as either mandatory or discretionary, consistent with the criteria described in Exhibit B, Tab 1, Schedule 1, Section 2.1. The graph included in SEC-32, includes mandatory investments, and subsequently discretionary investments, with expenditures planned over the 2019-24 period, as shown below:

Tx Capital – Power Systems – Risk Spend Efficiency Chart



1. Includes Power System investments only. Value for other allocations are primarily evaluated on productivity or flagging basis
2. Ranking based on investments flagged as Mandatory followed by Risk Spend Efficiency. For presentation purposes, investments with an efficiency rating greater than 500k points have been set at 500k; those with an efficiency raring of 0 have been set at 10

Mandatory investments meet one of the four mandatory flag criteria outlined in TSP 2.1, page 37 and reproduced below:

Witness: Bruno Jesus

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

In some cases, mandatory investments were not re-scored because they were in-flight, or were scored low based on a compliance obligation.

	ISD	ISD Name	2019-2024 Spend ($ M)	Total Risk Mitigation	Risk Spend Efficiency[1]
Mandatory[2]	SA-01	Connect New IAMGOLD Mine	10	-	-
	SA-02	Horner TS: Build a Second 230/27.6kV Station	6	-	-
	SA-03	Halton TS: Build a Second 230/27.6kV Station	6	-	-
	SA-04	Connect Metrolinx Traction Substations	11	-	-
	SA-05	Future Transmission Load Connection Plans	19	-	-
	SA-06	Protection and Control Modifications for Distributed Generation	-	879,930	500,000
	SA-07	Secondary Land Use Projects	-	-	-
	SR-01	Air Blast Circuit Breaker Replacement Projects	219	10,897,936	49,845
	SR-02	Station Reinvestment Projects	142	115,142	813
	SR-03	Bulk Station Transformer Replacement Projects	20	251,406	12,274
	SR-05	Load Station Transformer Replacement Projects	51	65,233	1,272
	SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	20	21,795	1,088
	SR-10	Transformer Protection Replacement	7	-	-
	SR-15	Telecom Fibre IRU Agreement Renewals	15	3,190,264	206,982
	SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	49	585,075	11,967
	SR-24	Transmission Line Shieldwire Replacement	74	665,383	8,982
	SR-26	Transmission Line Emergency Restoration	59	1,992,879	33,552

[1] Investments with an efficiency rating of 0 are either in-flight or driven by regulatory compliance, contractual commitments, customer requests or economical efficiencies.
[2] Certain System Renewal investment are included in both the Mandatory and Discretionary categories based on the taxonomies as certain sites are currently in-flight. Refer to TSP 2.1 pages 37-38 for mandatory/discretionary categorization.

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	ISD	ISD Name	2019-2024 Spend ($ M)	Total Risk Mitigation	Risk Spend Efficiency[1]
	SS-01	Lennox TS: Install 500kV Shunt Reactors	46	-	-
	SS-02	Wataynikaneyap Power Line to Pickle Lake Connection	30	-	-
	SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits	-	-	-
	SS-04	East-West Tie Connection	127	-	-
	SS-05	St. Lawrence TS: Phase Shifter Upgrade	18	-	-
	SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	24	-	-
	SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	194	-	-
	SS-08	Northwest Bulk Transmission Line	35	-	-
	SS-09	Barrie Area Transmission Upgrade	75	-	-
	SS-10	Kapuskasing Area Transmission Reinforcement	28	-	-
	SS-11	South Nepean Transmission Reinforcement	1	-	-
	SS-12	Alymer-Tillsonburg Area Transmission Reinforcement	30	-	-
	SS-13	Leamington Area Transmission Reinforcement	206	-	-
	SS-14	Southwest GTA Transmission Reinforcement	33	-	-
	SS-15	Future Transmission Regional Plans	44	-	-
	SS-16	Customer Power Quality Program	20	-	-
		Less than $3M	296	5,272,230	17,814
Discretionary	GP-02	Grid Control Network Sustainment	41	772,412	18,926
	GP-05	Transmission Non-Operational Data Management System	23	25,420	1,125
	SA-07	Secondary Land Use Projects	7	-	-
	SR-01	Air Blast Circuit Breaker Replacement Projects	464	60,937,116	131,344
	SR-02	Station Reinvestment Projects	458	22,478,975	49,088
	SR-03	Bulk Station Transformer Replacement Projects	392	22,150,917	56,472
	SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	176	65,981,862	374,265
	SR-05	Load Station Transformer Replacement Projects	719	10,637,910	14,799
	SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	225	10,137,180	45,150
	SR-07	Protection and Automation Replacement Projects	64	10,084,973	158,113
	SR-08	John Transformer Station Reinvestment Project	86	1,465,442	17,038
	SR-09	Transmission Station Demand and Spares and Targeted Assets	243	7,269,990	29,886
	SR-11	Legacy SONET System Replacement	115	1,008,208	8,731
	SR-13	ADSS Fibre Optic Cable Replacements	4	484,854	114,499

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	ISD	ISD Name	2019-2024 Spend ($ M)	Total Risk Mitigation	Risk Spend Efficiency[1]
	SR-14	Mobile Radio System Replacement	20	201,590	10,170
	SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	481	996,525	2,072
	SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	506	355,060	702
	SR-21	Wood Pole Structure Replacements	300	12,487,336	41,607
	SR-22	Steel Structure Coating Program	111	-	-
	SR-25	Transmission Line Insulator Replacement	407	14,289,148	35,117
	SR-27	C5E/C7E Underground Cable Replacement	127	176,963	1,390
	SR-28	OPGW Infrastructure Projects	32	321,485	10,041
		Less than $3M	402	20,108,484	50,065
Excluded		Less than $3M	360	32,790,878	91,171

As part of Enterprise Engagement and Challenge Sessions, trade-off decisions assess which investments should be promoted or demoted based on the following levers:

- **Risk:** Is Hydro One comfortable with the remaining risk? Are there unfunded investments which mitigate large risks?
- **Flags (non-risk parameters):** Which investments need to be funded for non-risk merits?

The consideration of risk efficiency and risk mitigated per dollar and other considerations supports the making of prudent and data-driven trade-off decisions. Investments that were prioritized out of the plan ("Excluded") have not been included in this application; examples of these candidate investments included power system telecom investments, station reinvestment and component replacements, replacement of wood pole structures in non-publicly accessible locations, and future line refurbishments which are expected to be assessed to be end-of-life at a later date.

UNDERTAKING - JT 1.21

Reference:
I-11-CCC-004

Undertaking:
To provide the underlying numbers for the two charts to derive the amounts.

Response:
a) The following table outlines the portion of Hydro One's major assets that had a high or very high risk condition and were considered to be end of life at the time of filing Application EB-2016-0160.

Hydro One has amended the table below (emphasis added) presented in Interrogatory I-CCC-004 part b) and originally provided in EB-2016-0160 Exhibit B1, Tab 2, Schedule 6, Figure 30 to reflect a correction to the calculation of High Risk or Very High Risk Wood Poles. Further details may be found at Undertaking JT 1.22.

Major Asset Condition Summary

Asset Type	% of Assets at High or Very High Risk	Count of Assets at High or Very High Risk	Total Population	EB-2016-0160 Reference
Transformers	15%	108	721	Exhibit B1, Tab 2, Schedule 6, Figure 5
Circuit Breakers	11%	499	4,543	Exhibit B1, Tab 2, Schedule 6, Figure 11
Protection Systems	27%	3,267	12,103	Exhibit B1, Tab 2, Schedule 6, Figure 18
Conductors (km)	9%	2,643	29,369	Exhibit B1, Tab 2, Schedule 6, Figure 24
Wood Poles	*12%*	*4832*	42,000	Exhibit B1, Tab 2, Schedule 6, Figure 30
Underground Cables (km)	4%	11	267	Exhibit B1, Tab 2, Schedule 6, Figure 48

Witness: Donna Jablonsky

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b) The following table outlines the portion of Hydro One's major assets included in this Application that have a high or very high risk condition and are considered to be at end of life.

Major Asset Condition Summary

Asset Type	% of Assets at High or Very High Risk	Count of Assets at High or Very High Risk	Total Population	EB-2019-0082 Reference
Transformers	17%	122	716	Exhibit B, TSP Section 2.2, Table 1 Exhibit B, TSP Section 2.2, Figure 3
Circuit Breakers	9%	460	4,774	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, Figure 8
Protection Systems	27%	3,363	12,506	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, p 26
Conductors (km)	13%	3,680	29,107	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, Figure 18
Wood Poles	13%	5,630	42,000	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, Figure 27
Underground Cables (km)	3%	8	264	Exhibit B, TSP Section 2.2, Table 1, p 3 Exhibit B, TSP Section 2.2, Figure 21

Witness: Donna Jablonsky

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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.

Witness: Donna Jablonsky, Robert Reinmuller

SR-01 Air Blast Circuit Breaker Replacement Projects

Start Date:	Q4 2013	**Priority:**	High
In-Service Date:	Q4 2027	**3 Year Test Period Cost ($M):**	366.2
Triggers: Strategic, System Renewal, Customer Engagement			
Outcome: Increase reliability and performance to large customers and generators; improve reliability to the BES, stage approach to minimize customer outages, reduce maintenance cost associated with End of Life ("EOL") equipment and air systems, reduce constrained power flow through the station; replace EOL PCT equipment; reduce costs of unplanned outages due to ABCB failures and leaking air systems.			

A. OVERVIEW

Air Blast Circuit Breaker Replacement Project (the "Project") involves the replacement of Air Blast Circuit Breakers ("ABCBs") and their auxiliary station equipment that are at a high risk of failure due to deteriorated condition and asset obsolescence. The principal drivers of the Project are unacceptable reliability performance, high operation and maintenance costs and unavailability of spare parts and technical support due to obsolescence. The majority of installed ABCBs have surpassed their EOL and the entire population of ABCBs will exceed their expected service life by the end 2023 if proactive replacements are not undertaken. Currently, the obsolescence of ABCBs, which were originally installed in the 1970s, already pose significant challenges in terms of the high operating costs required to maintain system reliability. The lack of available spare parts due to the obsolescence of the technology further constrains Hydro One's ability to maintain these assets and implicitly the resulting system reliability at the appropriate level. Almost half of Hydro One's ABCBs population is installed at critical stations that are delivery points to hydraulic, gas and nuclear plant operators and interties. Any forced outages at the critical stations due to ABCB failures would adversely impact these sensitive customers, who have expressed the view that a high level of reliability is paramount to their operations. To address customer concerns, high risk to reliability performance of deteriorated ABCB assets, and associated escalating maintenance costs, Hydro One evaluated several alternatives, as described below, and concluded that the have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

Table 2 - Total Investment Cost

($ Millions)	Prev. Years	2020	2021	2022	2023	2024	Forecast 2025+	Total
Capital[1] and Minor Fixed Assets	464.9	112.0	133.6	138.8	133.7	101.8	104.9	1,189.5
Less Removals	31.6	4.5	5.2	5.3	4.5	3.1	3.3	57.5
Gross Investment Cost	**433.3**	**107.5**	**128.4**	**133.5**	**129.2**	**98.7**	**101.5**	**1,132.1**
Less Capital Contributions	1.0	1.6	1.5	0.1	0.0	0.0	0.5	4.6
Net Investment Cost	**432.3**	**105.9**	**126.9**	**133.4**	**129.2**	**98.7**	**101.0**	**1,127.4**

[1] *Includes overhead at current rates.*

Table 3 below presents the projected costs on an individual project basis. It also provides the total cost, which includes costs incurred in previous years and forecasted beyond 2024, where applicable, for each individual project along with the proposed in-service date.

Table 3 - Detailed Total Project Costs

Project	Net Investment Costs ($ Millions)					20-24 Total ($M)	Project Total ($M)	In Service Date
	2020	2021	2022	2023	2024			
Richview TS	2.5	0.0	0.0	0.0	0.0	2.5	94.9	2020
Bruce A TS 230kV	6.3	0.1	0.0	0.0	0.0	6.5	111.2	2020
Beck #2 TS 230kV	12.4	11.6	8.9	0.3	0.0	33.1	110.2	2022
Middleport TS	27.3	22.6	11.2	12.9	1.9	76.0	104.6	2023
Nanticoke TS	13.4	17.1	14.8	9.3	0.9	55.6	59.4	2023
Cherrywood TS 230kV	17.2	13.4	13.8	4.2	0.0	48.6	88.9	2023
Lennox TS	5.9	4.6	5.8	2.0	0.0	18.3	88.1	2023
Bruce B SS 500kV	12.9	16.6	20.1	18.4	10.5	78.5	85.5	2024

Bruce A TS 500kV	3.7	21.0	21.9	38.0	38.6	123.2	147.3	2025
Essa TS	0.5	6.6	20.3	13.9	14.2	55.5	71.4	2025
Beck #1 SS 115kV	3.3	2.9	3.5	3.5	3.0	16.2	30.7	2026
Cherrywood TS 230kV/500kV	0.4	10.4	13.2	26.6	29.5	80.1	135.2	2027
Net Investment Cost	**105.9**	**126.9**	**133.4**	**129.2**	**98.7**	**594.0**	**1127.4**	

The factors influencing the cost of the Project include:

- The circuit breaker voltage level and the number of ABCB replacements – the higher the voltage levels the higher the cost of equipment needed. Higher voltage levels require additional space requirements due to increased electrical clearances, more structures and etc.
- The station design and configuration - foundation/structural replacements, in-situ or Greenfield replacement. Safety by design based on latest Hydro One standards (i.e. new clearance requirements, Arc Flash requirements and etc.)
- NERC and/or NPCC requirements require physical separation and redundancy
- Outage availability, and reduced contingency concerns customers. Outage availability is more difficult to achieve at nuclear facilities due to stricter contingency planning (N-2 contingency).
- By-pass construction where needed to minimize customer impacts. In many situations, to avoid constraining generation and power flow, additional by passes are required; these are costly to install and are typically removed at the end of the project (i.e. between $3 million and $5 million)

D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

Alternative 1: Reactive Component Replacement is a "Do Nothing" alternative and is based on reactive response as the failures occur, and replacing ABCB sub-components as

3.2.4.6 Review of Utilities' Management of Air Blast Circuit Breakers

The data EPRI collected from this survey has demonstrated that Hydro One's approach to managing ABCBs is consistent with the industry. More specifically, the survey found that the both minor and major maintenance of ABCBs are "more" to "much more costly/difficult" to perform, and "less" to "much less reliable" when compared to single pressure gas breakers. Principal drivers behind programmatic replacement were operation and maintenance costs and an unacceptable level of reliability/availability. The population of ABCBs utilized by the utilities has been reduced by two-thirds over the last decade, with no new ABCBs currently being installed. The lack of available spare parts to properly maintain these types of breakers has become problematic for utilities due to the age of the technology and obsolescence. Hydro One currently has 133 ABCBs in its system. Over the next five years, Hydro One plans to remove 95 ABCBs from service and replace them with SF6 equivalents. For more details pertaining to this project, refer to SR-01 *Air Blast Circuit Breaker Replacement Projects*.

3.2.4.7 Review of Utilities' Management of Oil Circuit Breakers

The data EPRI collected from this survey has demonstrated that Hydro One's approach to managing Oil Circuit Breakers ("OCB") is consistent with the industry. More specifically, the survey found that the OCBs are somewhat "more costly/difficult" for purposes of performing both minor and major maintenance. OCBs are somewhat "less reliable" when compared to single pressure gas breakers. Principal drivers behind programmatic replacement are: unacceptable reliability/availability and insufficient ratings for below 138 kV; and excessive costs, environmental, and other for above 138 kV. The population of OCBs utilized by the utilities has been reduced by 18% over the last decade and nearly 85% of OCBs that are currently installed are over 40 years old. Utilities have diminished abilities to properly maintain oil circuit breakers as no utilities have dedicated crews to perform internal inspections/refurbishments or dedicated shops/contractors to maintain and overhaul oil circuit breakers. The higher cost and difficulty associated with maintenance requirements when compared to newer technology and the lack of dedicated crews to work on the ever-aging population of installed OCBs may lead to longer outage times associated with both routine and emergency maintenance. Hydro One currently has 1,600 OCBs in its system. Over the next five years, Hydro One plans to replace 247 OCBs with SF6 equivalents. OCB replacements are included as part of the following ISDs:

- SR-01 - *Air Blast Circuit Breaker Replacement Projects*
- SR-02 - *Station Reinvestment Projects*
- SR-03 - *Bulk Station Transformer Replacement Projects*
- SR-04 - *Bulk Station Switchgear and Ancillary Equipment Replacement Project*
- SR-05 - *Load Station Transformer Replacement Projects*
- SR-06 - *Load Station Switchgear and Ancillary Equipment Replacement Projects.*

For more details pertaining to these investments, refer to the ISDs noted above.

3.2.4.8 ESL Assessment of Specific Relays

This Kinectrics study was carried out to determine the risk associated with operating solid state and microprocessor relays beyond ESL and inform Hydro One of replacement pacing. The study was based on the samples of the currently in-service solid state and microprocessor-based relay population. These samples of relays were subject to accelerated aging tests. The report identified that the ESL range used by Hydro One is in-line with utility practice of 13 to 19 years for solid-state relays and a range of 13 to 20 years for microprocessor relays. The study results recommended Hydro One to increase the ESL for solid-state and microprocessor relays but did not provide a recommended ESL level.

While the study results confirm that Hydro One's ESL and treatment of these relays is appropriate and aligned with industry best practices. Hydro One will review its current practices and decision making process as well as continue to track and monitor the performance of its relays, based on the report's recommendations, to maximize the

Review of Utilities' Management of Oil Circuit Breakers

Current Industry Practices

Technical Update, April 2018

EPRI Project Manager
B. Desai

Utility Experience

For this study, utilities were asked to rate their experience with oil circuit breakers with respect to single pressure gas breakers. The three categories for rating utility experience were reliability and maintenance practices, cost/difficulty of performing minor maintenance, and cost/difficulty of performing major maintenance. The following subsections detail the gathered responses for each utility.

Reliability and Maintenance Practices

Table 3-7 shows that three of the five utilities surveyed found that oil circuit breakers are less reliable than single pressure gas breakers while one of the five utilities found them to have similar reliability. One out of the five utilities responded that oil circuit breakers are more reliable than single pressure gas breakers.

Table 3-7
Reliability of Oil Circuit Breakers to Single Pressure Gas Breakers (5 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Much Less Reliable						
Less Reliable	X			X		X
Same					X	
More Reliable		X				
Much More Reliable						

Cost/Difficulty of Performing Minor Maintenance

Table 3-8 shows that two of the six utilities surveyed found that oil circuit breakers are more costly/difficult to perform minor maintenance than single pressure gas breakers while three of the six utilities found them to be of similar cost/difficulty. One out of the six utilities responded that oil circuit breakers are less costly/difficulty than single pressure gas breakers.

Table 3-8
Cost/Difficulty of Performing Minor Maintenance of Oil Circuit Breakers Compared to Single Pressure Gas Breakers (6 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Much More Costly/Difficult						
More Costly/Difficult	X			X		
Same		X	X			X
Less Costly/Difficult					X	
Much Less Costly/Difficult						

Cost/Difficulty of Performing Major Maintenance

Table 3-9 shows that two of the six utilities surveyed found that oil circuit breakers are more costly/difficult to perform major maintenance than single pressure gas breakers while four of the six utilities found them to be of similar cost/difficulty.

Table 3-9
Cost/Difficulty of Performing Major Maintenance of Oil Circuit Breakers Compared to Single Pressure Gas Breakers (6 Respondents)

Option	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Much More Costly/Difficult						
More Costly/Difficult			X	X		
Same	X	X			X	X
Less Costly/Difficult						
Much Less Costly/Difficult						

Current Maintenance Practices

Utilities were asked several questions on current maintenance practices of in-service oil circuit breakers. The responses for each utility by question are shown in Table 3-10. Free form comments for each of these questions can be found in Table 3-11.

Only 33.3% of the utilities surveyed have dedicated crews to perform internal inspections/refurbishments on oil circuit breakers. None of the utilities have dedicated shops to maintain/overhaul oil circuit breakers and none have dedicated contractors to maintain/overhaul these breakers. 66.6% of the utilities have a reliable source of available spare parts.

Utilities were asked if they followed vendor-recommended preventive maintenance tasks and frequencies. 50% of utilities followed vendor recommendations. Although vendors informed utilities' initial maintenance programs, preventive maintenance tasks and frequencies are derived through local learnings via operating experience and manufacturer-specific reliability. One of the six utilities mentioned they perform supplementary tasks, in addition to scheduled preventive maintenance and overhauls, at critical locations to extend the life of oil circuit breakers.

Table 3-10
Maintenance Practices for In-Service Oil Circuit Breakers (6 Respondents)

Question	Utility 1	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Do you have dedicated crews to do internal inspections/refurbishments?	✖	✖	✖	✖	✓	✓
Do you have dedicated shops to maintain/overhaul these breakers?	✖	✖	✖	✖	✖	✖
Do you have dedicated contractors to maintain/overhaul these breakers?	✖	✖	✖	✖	✖	✖
Do you have reliable spare parts availability?	✖	✓	✓	✖	✓	✓
Do you follow vendor recommended PM tasks and frequencies?	✖	✖	✓	✓	✓	✖
Do you have additional tasks to extend the life of these breakers in addition to scheduled PMs and breaker overhaul?	✖	✖	✖	✓	✖	✖

3.2.4.1 Operating Spare Transformers Requirement Assessment

This study found that the results of Hydro One's Markov model analysis (used to determine the appropriate number of spare transformers), aligns with the independent and alternative analysis from the third-party expert, Electric Power Research Institute ("EPRI"). Hydro One continues to take steps to achieve and maintain the required quantity of operating spare transformers to ensure reliability and improve cost efficiency.

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. This pacing of transformer replacement has been reflected in the following ISDs: SR-02 (Station Reinvestment Projects), SR-03 (Bulk Station Transformer Replacement Projects), SR-05 (Load Station Transformer Replacement Projects), and SR-08 (John Transformer Station Reinvestment).

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. However, older circuit breakers are being replaced at a quicker rate than expected. The reason for faster paced replacement is due to replacement criteria that are not included in the EPRI report as explained below.

Hydro One plans to address 638 breakers over the planning period. This includes the removal of 49 breakers as a result of station decommissioning and reconfiguration as well as the additional installation of 15 breakers resulting from customer requests to increase operational flexibility in the Toronto area. As per the EPRI analysis, there is a 90% probability that Hydro One will need to replace 491 breakers or fewer. However, Hydro One's volume of replacement over the plan period is higher primarily due to obsolescence concerns, safety concerns (e.g. insufficient arc resistance), PCB mitigation, and integrated investments which are not reflected in the EPRI analysis.

The EPRI analysis is derived from asset retirement data from 1981 to 2017. The analysis does not reflect the necessary replacement of 95 ABCBs over the planning period due to worsening reliability, as Hydro One has operated its fleet longer than industry peers. Similarly, the historical mid-life refurbishment of oil breakers from 1950 to 2007 has enabled Hydro One to operate approximately 300 currently in-service breakers for a longer period prior to retirement. Based on how the calculations were performed, this skews the predicted replacement rate. PCB mitigation also contributes to the increased rate of replacement in order to meet federally legislated deadlines. Out of the 247 oil circuit breakers identified for replacement over the planning period, 69 (28%) have measured above the acceptable level of 45 ppm for PCBs. Due to increased obsolescence concerns and the lack of, or reduction of, vendor support with respect to oil, metalclad, and vacuum breakers, the capital plan paces breaker replacements to mitigate reliability impact. Where breakers that are not end of life are removed from service because it is part of an integrated investment (e.g., due to the replacement and relocation of a switchyard), these breakers are placed into spares to support the remaining fleet. Oil circuit breakers can be salvaged for parts to support the remaining fleet, while complete SF6 breakers are placed into the spare equipment pool to support demand replacements.

This pacing of circuit breaker replacement has been reflected in the following ISDs: SR-02 *Station Reinvestment Projects*, SR-04 *Bulk Station Switchgear and Ancillary Equipment Replacement Projects*, SR-06 *Load Station Switchgear and Ancillary Equipment Replacement Projects*, and SR-08 *John Transformer Station Reinvestment.*

Witness: Bruno Jesus/Donna Jablonsky/Robert Reinmuller

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3.2. Level 2 Assessment: Technical Parameters Robustness

Having completed the first level of our assessment, this section examines the AA and ARA capabilities from the perspective of tests, diagnostics and assessment applied to individual asset classes that the capabilities evaluate. To accomplish this, METSCO examined the scope of input data and the analytical methodologies applied to derive the AA Composite Risk Index for each of the evaluated asset classes. We also reviewed the input information supporting the broader ARA procedure, along with the strategic and operational documents, developed on the basis of, and in the course of collecting the insights generated through the ARA process.

In this context, our review of asset class-specific information considered in the scope of AA and ARA assessments is structured around three issue areas (where they are relevant), namely:

- *Input Data Supporting the AA Framework*: Integrity of the inputs used to support the AA framework, by measuring the sample sizes of the data that was utilized.
- *AA Evaluation Score Criteria & Results:* Completeness of the criteria used and methodologies applied to support the evaluation category scoring results.
- *Asset Risk Assessment Components*: Assessment on the incremental inputs used in supporting the ARA procedure, including strategic and operational documents.

We supply our observations and recommendations grounded in our in-depth review and assessment within each subsection.

3.2.1. Station Power Transformers

Input Data Supporting the Power Transformer AA Framework

The Asset Analytics formulation for Station Power Transformers leverages all six evaluation categories (i.e. Demographics, Condition, Performance, Utilization, Economics, Criticality) in order to produce an overall composite risk score. Our review of data availability across all input variables supporting each evaluation category score, suggests that on average, approximately 80% of requisite data entries across evaluation categories are populated with actual data, the remainder being supplied by default scores devised by SMEs, and/or missing. Figure 6 illustrates the average data availability across the inputs for each evaluation category[2].

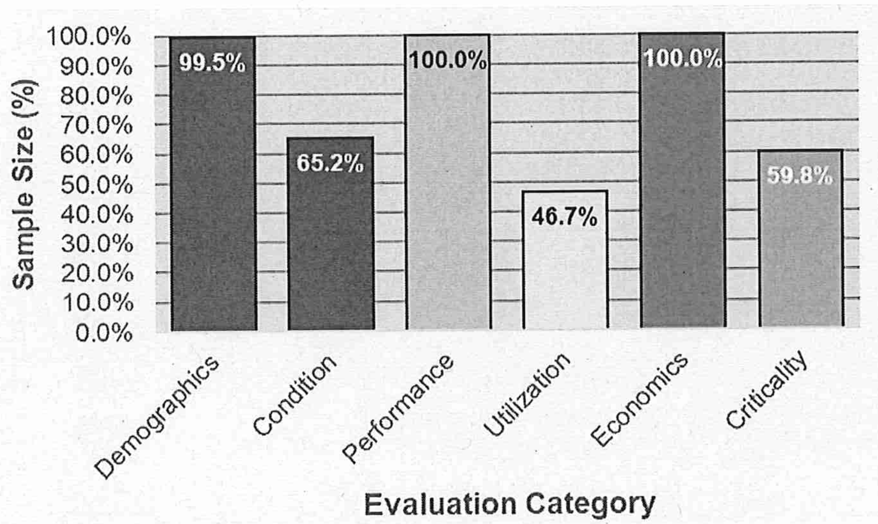

Figure 6. Station Power Transformer Average Sample Sizes for each Evaluation Category

On balance, METSCO finds that the average data availability levels across all six categories is satisfactory to make inferences and construct sub-indices for further evaluation (recall that the AA capability generates flags and scores to indicate missing or default data to notify asset managers where caution is required).

While the actual Condition data availability score of 65.2% may seem insufficient, METSCO finds it to be robust, considering the size of HONI's asset base, the span of its territory, and the manner of presentation of the condition score relative to many other utilities. Notably, and unlike most condition scores that feature in rate applications in the form of Health Indices (HI), Hydro One's condition data availability score does not include any age or utilization data (each captured in their separate demographic category), which are often included in Health Index formulas and are used (correctly) to represent discrete facets of asset health. Instead, the condition captured within HONI's Condition category is related solely to data on asset's extent of degradation, as assessed by Hydro One's field crews, and established by empirical tests like Dissolved

[2] The overall data availability score referenced above was calculated on the basis of average across all individual input values in all categories - not across the averages of each individual category

CME INTERROGATORY #13

Reference:
TSP-01-04p. 8 of 32

Interrogatory:
At Exhibit B, Tab 1, Schedule 1, TSP Section 1.4, page 8 Hydro One states that: "Hydro One's transformer condition assessment practices are aligned with industry best practices. 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. Hydro One depends on the subject matter experts to account for these issues. Therefore, Hydro One will continue its current practices and will track and monitor future test results."

a) What are the consequences of Hydro One's analysis not aligning with EPRI's PTX analysis?

b) What will the subject matter experts do to ameliorate this non-alignment? Have they done that previously, or will this be a new activity?

c) How do the 19.5% of assessments that are not aligned interact with the condition data availability found by Metsco in its Review of Hydro One's Capabilities in Transmission Asset Analytics & Reliability Risk Modelling in Exhibit B, Tab 1, Schedule 1, TSP Section 1.4, Attachment 13, p. 40 of 106? Do the non-alignments overlap with instances where there is no condition data, or are they in addition to those instances?

Response:

a) Hydro One performed further assessments to evaluate the condition of the unit and took action accordingly. <u>Incorrect data</u> due to data entry or collection error. The incorrect data were corrected manually. Also Hydro One has started a project together with the test laboratories who perform oil analysis to automatically populate transformer oil test results in our data base to enhance the accuracy level of the data. This project is now in test stage and will be completed by the end of 2019. <u>Correct</u>

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.

b) The SME evaluates the unit based on the testing data, operation history, and maintenance records of the transformer. This is a standard practice in Hydro One.

c) Misalignment between EPRI and Hydro One asset condition assessment is mainly due to interpretation of raw data provided to EPRI not missing data. METSCO's finding is mainly referring to missing data. Therefore, these two findings do not overlap.

Witness: Donna Jablonsky

hydro one

INTERNAL AUDIT REPORT

Investment Planning Support Tools

To:

Darlene Bradley
Vice President, Planning

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Greg Kiraly	Chief Operating Officer
Chris Lopez	Senior Vice President, Finance
Bruno Jesus	Director, Strategy & Integrated Planning
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Additional Recipients	Email Distribution List

Final Report Issued: October 31, 2017
Draft Report Issued: August 31, 2017
Report Number: 2017-17

Lead Auditor: Atul A. Solanki
Audit Manager: Jeff Schaller

EXECUTIVE SUMMARY

Background:

The annual Investment Plan Proposal details investments and resulting work programs required to develop and sustain transmission and distribution assets and system capabilities. This plan represents a substantial portion[1] of the Hydro One's Corporate Business Plan that is approved annually by Hydro One's Board of Directors. The Planning organization uses software tools such as Asset Analytics and Asset Investment Planning to support the development of the annual Investment Plan Proposal. The Asset Analytics tool[2] is used to assess asset demographics and condition data to provide input to asset refurbishment and replacement decisions over a 30 year time frame. The Asset Investment Planning tool[3] (aka Copperleaf C55 software solution) is used to select the best investment alternative based on the timing of the investment that will maximize risk mitigation and financial benefits while satisfying pre-determined constraints and dependencies. Both of these tools have been in place for several years.

Objective & Scope:

The primary objective of this audit was to provide assurance that key controls are in place for the effective use of the Asset Analytics and Asset Investment Planning tools to support the investment planning process.

Our work included a review of:

- Governance (clarity of roles, accountabilities, process, training, communication, etc.) related to the setup and utilization of the Asset Analytics and Asset Investment Planning tools.
- Control Activities (including documented definitions of input data requirements, data processing and validation of tool outputs).
- Monitoring of consistent and effective use of both tools in support of development of the annual Investment Plan Proposal.

Excluding:

- IT related work for software tool licensing, configuration, upgrades, vendor support, etc.
- Known asset data governance issues which were addressed in a separate audit (Audit Report 2016-15 SAP Data Integrity Follow-up and Data Governance Review)

Audit Opinion:

Process improvements are currently underway for the Investment Planning process as part of the 2017 investment planning cycle and this has resulted in a rigorous use of the Asset Investment Planning tool, however the use of the Asset Analytic tool has been limited and inconsistent. Based on the specific areas reviewed, **we concluded that controls over the Asset Investment Planning tool are generally effective while control improvements are needed over the Asset Analytics tool** to ensure consistent and effective use of these tools to develop the annual Investment Plan Proposal.

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[1] The Investment Plan Proposal represented aapproximately 70% of the Corporate Business Plan in 2015.

[2] Asset Analytics (AA) tool comprises of a software solution from SpaceTime Insight Inc. and SAP Business Intelligence that has been customized for use within Hydro One.

[3] Asset Investment Planning (AIP) tool is the name of Hydro One's implementation of a commercial off the shelf software from Copperleaf Inc.'s C55 software solution for Asset Investment Planning & Management.

Success Factors:

We noted that the following success factors were in place:

Asset Analytics:
- A formal process is in place for identifying and escalating Asset Analytics tool related issues to Help One for resolution.
- Two full-time resources support the Asset Analytics tool with an annual sustainment budget of approximately $455k.
- Six Asset Risk Indexes (ARIs) are being calculated within Asset Analytics using data from nineteen different systems for the majority of transmission and distribution assets.

Asset Investment Planning:
- Annual refresher training is provided to Planners by the Investment Planning and Process team using updated training materials as well as job aids along with one-on-one support for specific needs.
- Three members of the Investment Planning and Process team support the Asset Investment Planning tool on a part-time basis with an annual sustainment budget of approximately $160k.
- Nine measures were in place during 2016 investment planning cycle to monitor effective use of the Asset Investment Planning tool and related processes. Additional measures are planned for the 2017 investment planning cycle.
- Lessons learned related to the use of the Asset Investment Planning tool are captured as part of the overall investment planning process. Members of the Investment Planning and Process Team are part of the Copperleaf Community Advisory Board and take part in the Community Online Forum as well as industry conferences to share their knowledge and experience with peer utilities.
- A detailed process is available and used to configure Asset Investment Planning tool, perform quality assurance of data input, run optimization engine and review optimization results.

Summary of Key Recommendations:

We have discussed our observations with management throughout this audit. The key recommendations we made, which management has reviewed and developed action plans, are included in the following list of high and medium residual risk impact items:

High Risk:
- Ensure that the needs for changes to data and algorithms for asset risk index calculation, which are already identified by management, are prioritized and implemented on a timely basis.
- Ensure that appropriate mechanisms are in place for periodic monitoring, escalation for follow-up and correction of known data quality issues with the owners of the supporting data systems so that Asset Analytics input data quality continues to improve.

Medium Risk:
- Develop and implement suitable measures to periodically monitor consistent and effective use of Asset Analytics within Planning and to ensure that this tool is being used for its intended purpose.
- Develop and communicate appropriate guidelines to ensure consistent and effective use of available Asset Analytics data and tool capabilities for investment planning assessment needs.
- Review the current use of the Asset Analytics tool capabilities and features and determine which are required for on-going use. Perform a cost/benefit review of features to determine their continued use.

Provide the required training and support for capabilities that are available (such as ad-hoc BOBJ Reports[4]).

Management has developed action plans to mitigate the identified risks and address our recommendations, as summarized in Attachment "A" of this report. In a separate memorandum, we have shared with management additional opportunities for improvement, which we believe will further strengthen this function. Additional details are available upon request.

Management Response:

Bruno Jesus, Director, Strategy & Integrated Planning

Hydro One Management is in agreement with the proposed issues and recommendations and are very committed to implementing the resulting action plans for resolution.

[4] SAP Business Objects (BOBJ) is a reporting tool being used to create both ad-hoc and formal reports using the available data from the data warehouse that contains data from various source systems including SAP.

Observations	Recommendations	Action Plan
1.0 Measures related to Asset Analytics use are unavailable	**Risk**[5] M	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Currently, there are no measures in place to periodically monitor consistent and effective use of Asset Analytics (AA). Although an AA user list is available on a monthly basis, it does not adequately monitor the effective use of the AA data and tool capabilities. There are approximately 900 individuals approved to use the AA tool but it is unclear how many users are actually using AA and for its intended purpose. Five measures related to monitoring of continued acceptance of AA by users were envisioned during AA implementation. Currently none of these measures are either implemented or tracked. ***Risk:*** *A lack of monitoring for effective use of the support tool could lead to inconsistent or inappropriate use of the tool or inability to leverage available tool capabilities.*	Develop and implement suitable measures to periodically monitor consistent and effective use of AA within Planning.	We will review the existing use of AA tool capabilities and develop measures for its effective use that can be tracked as part of the Planning Scorecard. **Completion:** March 31, 2018

[5] Residual Risk levels applied are described in the legend that follows this table.

Observations	Recommendations	Action Plan
2.0 Asset Analytics Algorithms require improvement to be effective	**Risk** H	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Since the implementation of Asset Analytics in 2012 (Wave 1) and 2014 (Wave 2), Management has recognized that further improvements are needed to the existing Asset Risk Index (ARI) algorithms and data, along with new ARIs related to Obsolescence and Health, Safety and Environment. The 159 currently proposed enhancements are organized into three categories: a) Enhancements related to existing ARI algorithms and existing data, b) Enhancements related to existing ARI algorithms requiring new data, and c) Enhancements related to new ARI algorithms and new data. We were informed by Management that plans are underway to address the a) & b) enhancements by end of 2020 as per the current approved business plan and management is planning to expedite these changes to be completed by end of 2018 as per the business plan currently under development. ***Risk:*** *Untimely correction of known issues with AA algorithms can reduce the effectiveness and use of the AA tool for its intended purpose.*	Ensure that the identified needs for changes to data and algorithms for asset risk index calculation are prioritized and implemented on a timely basis.	As per our current plan, we will monitor the implementation of a) enhancements related to existing ARI algorithms and existing data and b) enhancements related to existing ARI algorithms requiring new data enhancements by end of 2018. We will look for opportunities to expedite this work along with c) Enhancements related to new ARI algorithms and new data. **Completion:** December 31, 2018

Observations	Recommendations	Action Plan
3.0 Asset Analytics input data quality remains poor	**Risk** H	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Poor quality data from source systems that are used as inputs to the Asset Analytics (AA) tool has resulted in unreliable Asset Risk Index calculations/outputs from the tool. The input data quality is determined by accuracy, completeness and timely availability of these data largely provided by other line of business groups. An SAP data dashboard is currently available to indicate completeness of SAP asset and static nameplate data (such as ratings, volume, etc.) used for ARI calculations, however a similar mechanism is unavailable for completeness of SAP dynamic data (such as counter readings, test results, condition ratings, etc.) or input data from the other 18 supporting systems into the AA tool. The AA tool has built in data quality measures for each ARI, namely, Data Completeness (DC) and Confidence Level (CL). Analysis of these measures for stations and lines asset composite ARI show that stations assets have low data completeness while lines assets have low confidence levels. A composite ARI is currently unavailable for 10 asset types. The input data from source systems used in ARI algorithms are known as Supporting Factors. An analysis of Supporting Factor availability shows that there has been only a marginal improvement between 2014 and 2017. Almost 10% of Supporting Factors for Distribution	Ensure that appropriate mechanisms are in place for periodic monitoring, escalation for follow-up and correction of known data quality issues with the owners of the supporting data systems.	We will discuss source system data quality issues with the system owners and then implement periodic monitoring and correction of identified issues by the system owners. **Completion:** June 30, 2018

Observations	Recommendations	Action Plan
Stations are either missing or using default values while 12% of Supporting Factors for Transmission Stations are either missing or using default values. There are informal mechanisms in place to identify and escalate missing/inaccurate data for correction in supporting systems once they are identified by the Planners as part of the field validation/review, however there is inadequate follow-up and monitoring to ensure that this occurs in a timely manner. Enhancements currently planned for algorithm updates (discussed in observation 2.0 of this report) are not expected to address the underlying data quality issues from support systems. ***Risk:*** *Poor quality input data and output results or timely correction of known issues would reduce the effectiveness and use of the Asset Analytics support tool for its intended purpose.*		
4.0 Asset Analytics use guidelines are unavailable	**Risk** M	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Although the use of the Asset Analytics (AA) tool is governed by the Asset Risk Index policy (SP1213) and related Directive (SP1204), there is a lack of specific documented expectations or guidelines on how the AA data and tool analytical capabilities and features	Develop and communicate appropriate guidelines to ensure consistent and effective use of available AA data and tool capabilities for investment planning assessment needs.	We will review and formalize the current Asset Risk Assessment process in our policy documents along with revision and/or development of suitable processes, procedures,

frameworks found elsewhere in the industry, and are sufficiently rigorous and robust to accomplish their intended tasks from an analytical perspective. Both ARA and AA are predominantly in line with advanced industry practices, with certain analytical elements approaching best-in-class capabilities.

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, Mestco 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 reflects continuous improvement in this area. However, as Hydro One uses 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.

The overall results of these studies demonstrate that Hydro One optimizes the life cycles of its assets and selects the appropriate assets for replacement in the Business Plan. This shows that Hydro One is well positioned to provide value to customers.

The technical findings from the studies are provided in Section 1.4.3, below. TSP Section 3.2.4 describes how Hydro One's proposed capital expenditure plan reflects the results of these studies/assessments.

1.4.2.1 RESULTS OF PTX ANALYSIS OF HYDRO ONE'S TRANSFORMER FLEET

Assessing the condition of in-service equipment accurately and efficiently is a critical step in asset management. In the context of a transmission system, there is no equipment for which this is more important than power transformers. Hydro One engaged EPRI to assess the condition of its transformers using the PTX analysis program. EPRI developed the PTX methodology for assessing the condition of transformers by analyzing dissolved gas data from a utility's historical oil data records. PTX identifies transformers with abnormal test results that are then subject to further consideration as to whether more detailed testing or increased monitoring is warranted. The resulting report from EPRI provides an overview of the PTX methodology and presents the results of its analysis for those of Hydro One's transmission system transformers for which data was provided.

In the report, the results are classified by primary voltage class and vintage and have been categorized into five condition risk rankings.

The results obtained by EPRI using its PTX tool are closely aligned with the results of the condition assessment methodology that Hydro One currently uses. This confirms that Hydro One's transformer condition assessment practices are aligned with industry best practices. 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. Hydro One depends on the subject matter experts to account for these issues. Therefore, Hydro One will continue its current practices and will track and monitor future test results.

1.4.2.2 DERIVATION OF TRANSMISSION SUBSTATION TRANSFORMER HAZARD FUNCTIONS

While Hydro One focuses on asset health including factors such as condition, criticality, reliability, and cost for asset replacement decisions, the mean life expectancy of equipment fleet is a key requirement for long term planning. It informs resourcing requirements, outage coordination, rate impact, and long term project schedules from planning to execution of work. Insights on fleet mean life expectancy may be derived

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DATE: **August 12, 2019**

And I would ask you to clarify your response in (a).

So I think I understand the first part of your response, and I am hoping you can correct me if I am wrong, but the first part is with incorrect data, and that's just sort of either a clerical error or, you know, somebody misread a reading or mistyped something into a spreadsheet, that sort of thing; is that right?

MS. JABLONSKY: Agreed.

MR. POLLOCK: And then as I understand it, the sort of action plan or the ameliorative action was you changed all the values that you found that were incorrect and you're sort of reviewing a way to do it automatically so that these could be eliminated in the future; is that right?

MS. JABLONSKY: Yes.

MR. POLLOCK: Okay, so with respect to the second part, the correct data, you say the correct data does not reflect the true condition of the transformer. And it goes on.

But I was wondering if you could explain to me when correct data wouldn't reflect the true condition of a transformer and why.

MS. JABLONSKY: If we look at -- I will try to use an example. If I look at the transformer and I look at transformers wherein there's a breather between the main tank and the tap changer, I can have -- I can pull the oil from the transformer and/or pull the oil from the tap changer and get a contamination in it, so it would be correctly done, just that the values that I pull does not make sense.

MR. POLLOCK: Okay. So this isn't necessarily an issue of interpreting the data, this is, there is a collection, and it collected the correct data for maybe the tap changer but not for the main tank.

MS. JABLONSKY: Yes, when I look at the data it's showing PPM of much larger values than would have been in the tap changer, so then it's clear that something is wrong with what we have pulled.

MR. POLLOCK: And in terms of the sort of the reaction to that, as I understand it, the subject-matter experts will interpret the data and decide upon the appropriate course of action.

So am I right in thinking that that's currently what they were already doing, or is this a change in some way?

MS. JABLONSKY: This is currently what we have been doing and still do.

MR. POLLOCK: Right. So some percentage of the 19.5 percent were caused by these sort of misreadings, but you're not proposing to do anything different about it, so that percentage will probably stay the same.

MS. JABLONSKY: That percentage will probably stay the same, yes, because doing something about it is not all cases possible, because the design of the transformers, the way the transformer is designed.

So what we could do is look at different positions in the tank that can we can actually draw the oil, and we are able to do that sometimes.

MR. POLLOCK: Okay. And that's an ongoing thing that Hydro One Transmission --

MS. JABLONSKY: This is an ongoing thing in doing that, in doing that maintenance function.

MR. POLLOCK: Could we turn to CME number 17, please.

MR. KEIZER: Sorry, I don't mean to interrupt, but we talked about a break this morning at 11:00, and -- I believe that's what you indicated, Mr. Sidlofsky, and I just wanted to clarify with Mr. Pollock as to how long he is going to be.

MR. POLLOCK: Probably not more than five to seven more minutes, so if it's convenient I can keep going, but if you want to take a break that's fine.

MR. KEIZER: Why don't we finish then.

MR. SIDLOFSKY: I am going to suggest finishing CME, and we can take a break then if you like, Mr. Keizer.

MR. KEIZER: That would be great, thank you.

MR. POLLOCK: Is everyone on CME 17?

MS. JABLONSKY: Yes.

MR. POLLOCK: Okay. So I was trying to figure out from a new perspective how these flags work, the value flags for Hydro One. And I was wondering, are the standard default values which are arrived at from the subject-matter experts, are they different for each type of asset, like when you are going through each asset type and they all have the sub-criteria and you are missing data for some of them, do they have the same default values for each asset or are they different?